SUBSEQUENT LICENSE RENEWAL APPLICATION

Peach Bottom Atomic Power Station Units 2 and 3

Facility Operating License Nos. DPR-44 and DPR-56

The Second License Renewal Application July 2018

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1.0 ADMINISTRATIVE INFORMATION

1.1 GENERAL INFORMATION - 10 CFR 54.19

1.1.1 NAMES OF APPLICANT AND CO-OWNER

Exelon Generation Company, LLC (Exelon), hereby applies for subsequent renewed operating licenses for Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. Exelon submits this application individually and as agent for PSEG Nuclear LLC, co-owner.

1.1.2 ADDRESSES OF APPLICANT AND CO-OWNER

Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

PSEG Nuclear LLC
80 Park Plaza, T4B
Newark, NJ 07102

1.1.3 DESCRIPTIONS OF BUSINESS OR OCCUPATION OF APPLICANT

Exelon Generation Company, LLC is a Pennsylvania limited liability company which is wholly owned by Exelon Corporation, a corporation formed under the laws of the Commonwealth of Pennsylvania. Exelon Corporation, through its subsidiaries, is a major generator of electric power and a leading supplier of competitive electricity, with a current owned power generation portfolio of approximately 35,000 megawatts. Exelon Generation owns and operates the largest nuclear fleet in the United States. Exelon Generation Company, LLC is the licensed operator and co-owner of PBAPS Units 2 and 3, which is the subject of this application. The current PBAPS Units 2 and 3 operating licenses will expire as follows:

- At midnight on August 8, 2033 for Unit 2 (Facility Operating License No. DPR-44).
- At midnight on July 2, 2034 for Unit 3 (Facility Operating License No. DPR-56).

Exelon Generation Company, LLC will continue as the licensed operator on the subsequently renewed operating licenses.

1.1.4 DESCRIPTIONS OF ORGANIZATION AND MANAGEMENT OF APPLICANT AND CO-OWNER

Exelon Generation Company, LLC

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

Principal Officers (Exelon Generation Company, LLC and Nuclear Business Unit)		
Name	**Title**	**Address**
Michael J. Pacilio	Executive Vice President and Chief Operating Officer	4300 Winfield Road Warrenville, IL 60555
Bryan C. Hanson	Senior Vice President, Exelon Generation; President and Chief Nuclear Officer, Exelon Nuclear	4300 Winfield Road Warrenville, IL 60555
David P. Rhoades	Chief Operating Officer, Fleet Operations, Exelon Nuclear	4300 Winfield Road Warrenville, IL 60555
Daniel J. Enright	Senior Vice President, Midwest Operations	4300 Winfield Road Warrenville, IL 60555
Thomas J. Dougherty III	Senior Vice President, Mid-Atlantic Operations	200 Exelon Way Kennett Square, PA 19348
Christopher H. Mudrick	Senior Vice President, Northeast Operations	200 Exelon Way Kennett Square, PA 19348
J. Bradley Fewell	Senior Vice President - Regulatory Affairs, Assistant Secretary, and General Counsel	4300 Winfield Road Warrenville, IL 60555
George H. Gellrich	Vice President, Licensing, Regulatory Affairs and Nuclear Security	200 Exelon Way Kennett Square, PA 19348
Patrick D. Navin	Site Vice President, PBAPS	1848 Lay Road, Delta, PA 17314
Michael P. Gallagher	Vice President, License Renewal and Decommissioning	200 Exelon Way Kennett Square, PA 19348

PSEG Nuclear LLC

PSEG Nuclear LLC is a limited liability company organized under the laws of the State of Delaware, formed to own and operate nuclear generating stations. PSEG Nuclear LLC is a wholly-owned subsidiary of PSEG Power LLC, which is a wholly-owned subsidiary of Public Service Enterprise Group, Inc., with its principal office in Newark, New Jersey.

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

Board of Directors (PSEG Nuclear LLC)		
Name	**Title**	**Address**
Ralph A. LaRossa	Director	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Shahid Malik	Director	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Peter P. Sena	Director	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102

Principal Officers (PSEG Nuclear LLC)		
Name	**Title**	**Address**
Peter P. Sena	President and Chief Nuclear Officer	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Stuart J. Black	Vice President and Controller	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Eric Carr	Vice President - Hope Creek Generating Station	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Charles V. McFeaters	Vice President - Salem Generating Station	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Paul J. Davison	Vice President - Engineering	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Bradford D. Huntington	Vice President and Treasurer	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Peter W. Caruso	Assistant Treasurer	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Benjamin Zoe	Assistant Treasurer	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Michael K. Hyun	Secretary	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102
Donald S. Leibowitz	Assistant Secretary	PSEG Nuclear LLC 80 Park Plaza, T4B Newark, NJ 07102

PSEG Nuclear LLC is neither owned, controlled, nor dominated by an alien, foreign corporation or foreign government.

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

Exelon Generation Company, LLC requests a subsequent renewal of the Class 104 operating licenses for PBAPS Units 2 and 3, for a period of 20 years beyond the expiration of the current licenses to allow continued use of the facilities for the commercial generation of electricity. PBAPS Unit 2 license (DPR-44) expires at midnight on August 8, 2033. PBAPS Unit 3 license (DPR-56) expires at midnight on July 2, 2034.

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

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

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

1.1.7 RESTRICTED DATA

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

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

1.1.8 REGULATORY AGENCIES

Exelon Generation Company, LLC recovers its share of the costs incurred from operating PBAPS Units 2 and 3 in its own wholesale rates, and recovers the remaining costs from PSEG Nuclear LLC in relation to its ownership interest in PBAPS, Units 2 and 3. The rates charged and services provided by Exelon Generation Company, LLC are subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act.

PSEG Nuclear LLC also recovers its share of the costs incurred from operation of PBAPS Units 2 and 3 in its own wholesale rates, with the interstate sales of electricity regulated by FERC.

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

1.1.9 LOCAL NEWS PUBLICATIONS

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

LNP Media Group
8 West King Street
Lancaster, PA 17605
(717) 291-8811
Fax (717) 291-6507

York Daily Record
1891 Loucks Road
York PA 17408
(717) 771-2000
Fax (717) 771-2009

York Dispatch
1891 Loucks Road
York PA 17408
(717) 505-5418
Fax (717) 843-2814

The Star
811 Main Street
Delta, PA 17314
(717) 456-5692

The Aegis
139 N Main Street
Bel Air, MD 21014
(410) 838-4451
Fax (410) 838-2843

Cecil Whig
601 Bridge St
Elkton, MD 21921
(410) 398-3311
Fax (410) 398-4044

Cecil Guardian
113 E. Main Street
Elkton, MD 21921
(410) 392-9170

Rising Sun Herald
303 East Main Street
Rising Sun, MD 21911
(410) 658-5740
Fax (410) 658-2679

Patriot-News
2020 Technology Parkway
Suite 300
Mechanicsburg PA 17050
(717) 255-8176

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-28) for PBAPS 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 updated in Amendment 16, Item 3 of the Attachment to the indemnity agreement lists license number DPR-44 (for PBAPS Unit 2) and DPR-56 (for PBAPS Unit 3). Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current licenses and the terms of the renewed licenses. Applicant understands that no changes may be necessary for this purpose if the current license numbers for PBAPS Units 2 and 3 are retained.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSES, AND RENEWAL TERM OPERATION

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

In accordance with 10 CFR 54.21(d), Exelon Generation Company, LLC will maintain a summary description in the PBAPS, Units 2 and 3 Updated Final Safety Analysis Report (UFSAR) of programs and activities that are required to manage the effects of aging for the systems, structures, and components determined to be subject to aging management during the second period of extended operation, and summaries of the time-limited aging analyses evaluations.

1.2.2 INCORPORATION BY REFERENCE

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

1.2.3 CONTACT INFORMATION

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

Michael P. Gallagher
Vice President, License Renewal and Decommissioning
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

with copies to:

Donald B. Warfel
Manager License Renewal
Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

Paul R. Weyhmuller
License Renewal Project Technical Lead
Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

1.3 PURPOSE

This document provides information required by 10 CFR 54 to support the application for subsequent renewed licenses for Peach Bottom Atomic Power Station, Units 2 and 3. The application contains technical information required by 10 CFR 54.21 and environmental information required by 10 CFR 54.23. The information contained herein is intended to provide the NRC with an adequate basis to make the findings required by 10 CFR 54.29.

1.4 DESCRIPTION OF THE PLANT

PBAPS Units 2 and 3 are boiling water reactors (BWRs) located partly in Peach Bottom Township, York County, partly in Drumore Township, Lancaster County, and partly in Fulton Township, Lancaster County, in southeastern Pennsylvania on the westerly shore of Conowingo Pond at the mouth of Rock Run Creek. Conowingo Pond is formed by the backwater of Conowingo Dam on the Susquehanna River; the dam is located about nine miles downstream from the Unit 2 reactor. The plant is about 38 miles north-northeast of Baltimore, Maryland, and 63 miles west-southwest of Philadelphia, Pennsylvania. The reactor buildings are separate for each unit. The turbine building, control room, radwaste building, and diesel generator building house equipment used by both units. PBAPS Units 2 and 3 are BWR/4 reactor vessels designed and supplied by General Electric with 251-inch diameter vessels and 764 fuel assemblies. The primary containment of each unit is a Mark I design, consisting of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and the suppression chamber.

Each unit was originally authorized to operate at steady state reactor core power levels not in excess of 3293 megawatts thermal (MWt). In 1994 (Unit 2) and 1995 (Unit 3), the units were rerated to a maximum power level of 3458 MWt based upon original steam flow capability above rated power, improved analytical techniques, and more current fuel design. Subsequently, a license amendment was approved increasing the unit power levels to 3514 MWt based on the use of more accurate feedwater flow measurement equipment.

An Extended Power Uprate project was undertaken for both units, resulting in maximum core power levels of 3951 MWt being approved by the NRC in August 2014. The bases for these increased allowable power levels included continuing improvements in analytical techniques, fuel and core design, and plant hardware modifications, enabling plant power to be increased to approximately 20 percent above original licensed thermal power.

Finally, in November 2017 the NRC approved a measurement uncertainty recapture (MUR) license amendment, authorizing an increase in maximum power on each unit to 4016 MWt.

1.5 APPLICATION STRUCTURE

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

The application is divided into the following major sections:

Section 1 – Administrative Information

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

Section 2 – Structures and Components Subject To Aging Management Review

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

Additionally, the scoping and screening results for systems and structures are described in this section. Scoping results are presented in Section 2.2 "Plant Level Scoping Results”. Screening results are presented in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of passive long-lived mechanical and structural components that require aging management review. Brief descriptions of mechanical systems and structures within the scope of second license renewal are provided as background information. Mechanical system and structure intended functions are provided for in scope systems and structures. For each in scope system and structure, components requiring an aging management review are identified; associated component intended functions are identified; and appropriate reference to the Section 3 table providing the aging management review results is made.

Electrical components and selected structural components, such as electrical insulation for electrical cables and connections and component supports, respectively, were evaluated as commodities. Under the commodity approach, components were evaluated based upon common environments and materials. Components requiring an aging management review are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table is provided.

The descriptions of systems in Section 2 identify second license renewal boundary drawings that depict the components subject to aging management review for mechanical systems. These drawings are provided in a separate submittal.

Section 3 – Aging Management Review Results

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

Aging management review 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, aging management review results are provided in Sections 3.1 through 3.4 for the Reactor Vessel, Internals, and Reactor Coolant System; Engineered Safety Features; Auxiliary Systems; and Steam and Power Conversion Systems, respectively. Aging management review results for containments, structures, and component supports are provided in Section 3.5. Aging management review results for electrical and instrumentation and controls are provided in Section 3.6.

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

Section 4 – Time-Limited Aging Analyses

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

Appendix A –Updated Final Safety Analysis Report Supplement

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

Appendix B – Aging Management Programs

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

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

Appendix C – Response to BWRVIP License Renewal Applicant Action Items

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

Appendix D – Technical Specification Changes

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

Appendix E – Environmental Information – Peach Bottom Atomic Power Station, Units 2 and 3

This Appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report that complies with the requirements of subpart A of 10 CFR Part 51 for Peach Bottom Atomic Power Station, Units 2 and 3.

1.6 ACRONYMS

Acronym	**Meaning**
AC	Alternating current
ACI	American Concrete Institute
AFI	Area for improvement
ALE	Adverse localized environment
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American National Standards Institute
ART	Adjusted Reference Temperature
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASR	Alkali-silica reaction
ASTM	American Society for Testing and Materials
ATWS	Anticipated transient without scram
BTP	Branch technical position
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owner's Group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C (ºC)	Degrees Celsius
CAP	Corrective action program
CASS	Cast austenitic stainless steel
CFR	Code of Federal Regulations
CISI	Containment Inservice Inspection
CLB	Current licensing basis
CMAA	Crane Manufacturers Association of America
CMTR	Certified material test report
CRD	Control Rod Drive
CRDGT	Control Rod Drive guide tube
CRDRL	Control Rod Drive return line
CSE	Copper/copper sulfate reference electrode
CST	Condensate storage tank
CUF	Cumulative usage factor
CUF_{en}	Environmentally adjusted cumulative usage factor
CW	Circulating Water
DBA	Design basis accident

Acronym	Meaning
DBD	Design baseline document
DBE	Design basis event
DC	Direct current
DORT	Discrete Ordinates Transfer
EAF	Environmentally-Assisted Fatigue
ECCS	Emergency Core Cooling System
ECW	Emergency Cooling Water
EDG	Emergency Diesel Generator
EMA	Equivalent margin analysis
EFPY	Effective full-power years
EPRI	Electric Power Research Institute
EPA	Environmental Protection Agency
EPU	Extended power uprate
EQ	Environmental qualification
ESF	Engineered safety features
ESW	Emergency Service Water
EVT	Enhanced visual test
F (ºF)	Degrees Fahrenheit
FAC	Flow-accelerated corrosion
FASA	Focused area self-assessment
Fen	Environmentally assisted fatigue correction factor
FERC	Federal Energy Regulatory Commission
FHAR	Fire Hazards Analysis Report
FLR	First license renewal
FPP	Fire Protection Program
FSER	Final Safety Evaluation Report
FSSD	Fire safe shutdown
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report
GE	General Electric
GEH	General Electric Hitachi
GL	Generic Letter
GSI	Generic safety issue
HDPE	High-density polyethylene
HELB	High energy line break
HEPA	High efficiency particulate air

Acronym	**Meaning**
HPCI	High Pressure Coolant Injection
HPSW	High Pressure Service Water
HVAC	Heating, ventilation, and air conditioning
HX	Heat exchanger
I&C	Instrumentation and controls
IASCC	Irradiation assisted stress corrosion cracking
ICMH	In-core monitor housing
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular stress corrosion cracking
ILRT	Integrated leak rate test
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated plant assessment
ISFSI	Independent spent fuel storage installation
ISI	Inservice inspection
ISG	Interim staff guidance
ISP	Integrated surveillance program
IST	Inservice testing
JP	Jet pump
KSI	Kilo pounds per square inch
kV	Kilovolt
LAS	Low alloy steel
LER	Licensee event report
LLRT	Local leak rate test
LOCA	Loss-of-coolant accident
LPCI	Low pressure coolant injection
LRA	License renewal application
MEB	Metal enclosed bus
MELLA+	Maximum extended load line analysis plus
MeV	Million electron Volts
MG	Motor generator
MIC	Microbiologically influenced corrosion
MPa	Mega-Pascal
MSIV	Main steam isolation valve
MSRV	Main steam relief valve

Acronym	Meaning
MUR	Measurement uncertainty recapture (power uprate)
MWt	Megawatts-thermal
MWe	Megawatts-electric
NACE	National Association of Corrosion Engineers
NCV	Non-cited violation
NDE	Nondestructive examination
NDT	Nil ductility temperature
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NPS	Nominal pipe size
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSR	Nonsafety-related
OBE	Operational basis earthquake
OE	Operating experience
OEM	Original equipment manufacturer
OLTP	Original licensed thermal power
P&ID	Piping and instrumentation diagram
PBAPS	Peach Bottom Atomic Power Station
PDI	Performance demonstration initiative
PM	Preventive maintenance
PSI	Pounds per square inch
P-T curves	Pressure-temperature limit curves
PTLR	Pressure and temperature limits report
PWR	Pressurized Water Reactor
QA	Quality assurance
QATR	Quality assurance topical report
RAMA	Radiation analysis modeling application
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor coolant pressure boundary
RCS	Reactor coolant system
RG	Regulatory Guide
RIC	Recurring internal corrosion
RHR	Residual Heat Removal
RI-ISI	Risk informed inservice inspection
RPS	Reactor Protection System

Acronym	Meaning
RT_{NDT}	nil-ductility transition reference temperature
RPV	Reactor pressure vessel
RVI	Reactor vessel internals
RWCU	Reactor Water Cleanup
RWST	Refuel water storage tank
SBO	Station blackout
SCC	Stress corrosion cracking
SEI	Structural Engineering Institute
SER	Safety evaluation report
SGTS	Standby Gas Treatment System
SLC	Standby Liquid Control
SLRA	Second or subsequent license renewal application
SR	Safety-related
SRV	Safety relief valve
SRP-SLR	Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants
SSP	Supplemental surveillance program
SSCs	Systems, structures, and components
SSE	Safe shutdown earthquake
TLAAs	Time-limited aging analyses
TOC	Total organic carbon
TRM	Technical Requirements Manual
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate heat sink
USE	Upper-shelf energy
UT	Ultrasonic (volumetric) test
VT	Visual test
WANO	World Association of Nuclear Operators
WPC	Wear particle concentration
XLPE	Cross linked polyethylene

1.7 GENERAL REFERENCES

1.7.1 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”

1.7.2 NEI 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule,” June 2005

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

1.7.4 Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses”

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

1.7.6 NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report

1.7.7 10 CFR 50.48, “Fire Protection”

1.7.8 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants”

1.7.9 10 CFR 50.62, “Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants”

1.7.10 10 CFR 50.63, “Loss of All Alternating Current Power”

1.7.11 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”

1.7.12 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”

1.7.13 10 CFR 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions”

1.7.14 NUREG-0800, Section 9.5.1.1, Appendix B, “Supplemental Fire Protection Review Criteria for License Renewal,” Revision 5, March 2007

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

1.7.16 EPRI Technical Report 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4, January 2006

1.7.17 Plant Support Engineering: License Renewal Electrical Handbook, Revision 1 to EPRI Report 1003057 (1013475), Final Report, February 2007

1.7.18 “Plant Support Engineering: Aging Effects for Structures and Structural Components (Structural Tools),” EPRI, Final Report 1015078, December 2007

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

This section describes the process for identifying structures and components subject to aging management review in Peach Bottom Atomic Power Station (PBAPS) second license renewal integrated plant assessment. For the systems, structures, and components (SSCs) within the scope of second license renewal, 10 CFR 54.21(a)(1) requires the license renewal applicant to identify and list those structures and components subject to Aging Management Review (AMR). 10 CFR 54.21(a)(2) further requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2 of this application satisfies these requirements.

The 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 second license renewal in accordance with 10 CFR 54.4. The intended functions that are the bases for including the systems and structures within the scope of second license renewal are also identified during the scoping process. *Screening* is the process of determining which components associated with the in scope systems and structures are subject to an aging management review in accordance with 10 CFR 54.21(a)(1) requirements. A detailed description of the PBAPS scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is consistent with the guidelines presented in NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal (Reference 1.7.3). The plant level scoping results identify the systems and structures within the scope of second license renewal in Section 2.2. The screening results identify components subject to aging management review in the following LRA sections:

- Section 2.3 for mechanical
- Section 2.4 for structures and component supports
- Section 2.5 for electrical

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 INTRODUCTION

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

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

A mechanical system was included within the scope of second license renewal if any portion of the system met the scoping criteria of 10 CFR 54.4. Mechanical systems determined to be within the scope of second license renewal were then further evaluated to determine those system components that are required to perform or support the identified system intended function(s).

Second license renewal system descriptions were developed for each in scope mechanical system and are included in Section 2.3. These descriptions include relevant information from system descriptions included in the UFSAR. The in scope boundaries of mechanical systems were identified and are described in Section 2.3. These boundaries are depicted on the second license renewal boundary drawings (LRBD) by the use of boundary flags which identify second license renewal system interfaces. The in scope boundaries of the mechanical systems and in scope mechanical components are shown highlighted in green or red. Mechanical components that are required to perform or support safety-related functions or are required to demonstrate compliance with one of the five second license renewal regulated events are shown highlighted in green. Nonsafety-related mechanical components that are included within the scope of second license renewal because they provide structural support to safety-related SSCs are shown highlighted in red. Nonsafety-related mechanical components that are included within the scope of second license renewal because component failure could prevent the accomplishment of a safety-related function due to potential spatial interaction with safety-related SSCs are shown highlighted in red. The PBAPS first license renewal application and its associated supplements were developed pre-GALL and included consideration of spatial interaction for just active safety-related targets. The second license renewal application incorporates the latest standards for consideration of spatial interaction, which are defined in NEI 95-10, Revision 6, Appendix F (Reference 1.7.2), as referred to in NEI 17-01. The understanding of how to implement the spatial interaction aspects of 10 CFR 54.4(a)(2) evolved since the processing of the first several license renewal applications (including the first Peach Bottom LRA). In contrast to the industry position in the early 2000s, NEI 95-10 Revision 6 does not allow for the concept of “exposure duration” to limit the potential effects on certain (e.g., passive) safety-related components, that could occur from aging of nonsafety-related components; therefore, the scoping process for Peach Bottom SLRA requires including in scope any nonsafety-related SSCs that could impact active or passive safety-related targets. The evaluation for spatial interactions is described in more detail below in the subsection titled “Potential for Spatial Interactions with Safety-Related SSCs” in Section 2.1.5.2. Additional details on system scoping evaluations and boundary drawing development are provided in Section 2.1.5.

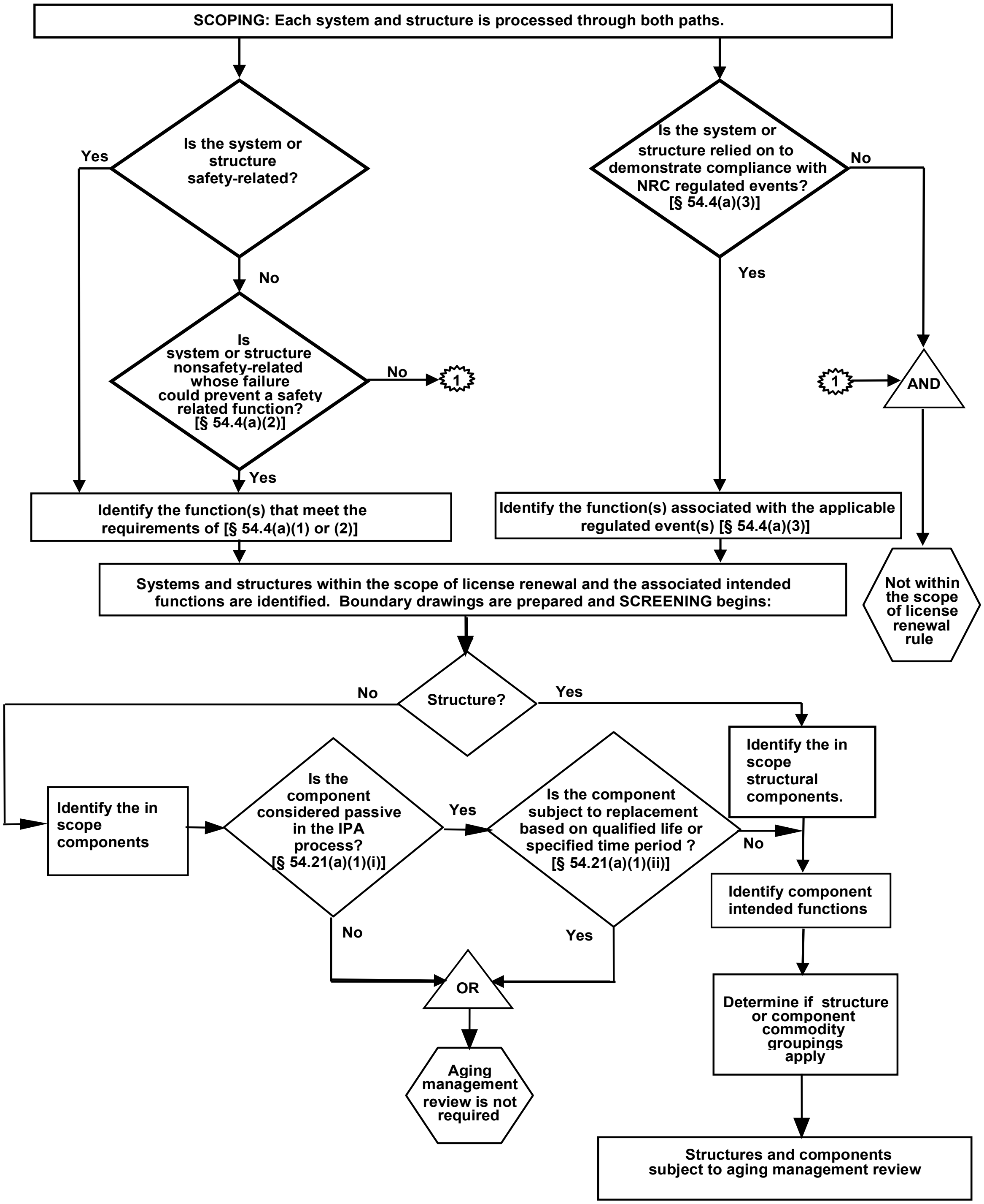
A structure was included within the scope of second license renewal if any portion of the structure met the scoping criteria of 10 CFR 54.4. Structures were then further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). Second license renewal structure descriptions were developed for each in scope structure and are included in Section 2.4. These descriptions include relevant information from structure descriptions included in the UFSAR. The structures that are within the scope of second license renewal are highlighted in green on the site plan. Additional details on structure scoping evaluations and boundary drawing development are provided in Section 2.1.5.

Electrical and Instrumentation and Control (I&C) systems were scoped like mechanical systems and structures per the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3). Electrical and I&C components within the in scope electrical and I&C systems were included within the scope of second license renewal. Likewise, electrical and I&C components within in scope mechanical systems were included within the scope of second license renewal. Additional details on electrical and I&C system scoping are provided in Section 2.1.5.

After completion of the scoping and boundary evaluations, the screening process was performed to evaluate the structures and components within the scope of second license renewal to identify the long-lived and passive structures and components subject to an Aging Management Review (AMR). In addition, the passive intended functions of structures and components subject to AMR were identified. Additional details on the screening process are provided in Section 2.1.6.

Selected components, such as component supports, hazard barriers and elastomers, electrical and instrumentation enclosures and raceways, and passive electrical components, were scoped and screened as commodities. As such, they were not evaluated with the individual system or structure, but were evaluated collectively as a commodity group. Passive structural commodities are identified in Section 2.4, and passive electrical commodities are identified in Section 2.5. Commodity groups utilized are consistent with Table 2.1-6 of NUREG-2192, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (Reference 1.7.5). Figure 2.1-1 provides a flowchart of the general scoping and screening process for mechanical systems, structures, and electrical systems.

Figure 2.1-1
Peach Bottom Atomic Power Station Scoping and Screening Flowchart



2.1.2 INFORMATION SOURCES USED FOR SCOPING AND SCREENING

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

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

2.1.2.1 Updated Final Safety Analysis Report

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

2.1.2.2 Fire Protection Program

The Fire Protection Program (FPP) describes the fire protection configuration for the confinement, detection, and suppression of fires, and demonstrates the capability to achieve and maintain safe shutdown conditions in the event of a fire, in support of the Fire Protection Program functions.

2.1.2.3 Environmental Qualification Master List

The scope of the electrical equipment and components that must be environmentally qualified for use in a harsh environment at PBAPS is identified in the Passport equipment database. The Passport equipment database is discussed in Section 2.1.2.7. The database includes a listing of equipment and components, and includes fields that identify specific equipment information such as manufacturer, plant location, and qualification level. The Passport equipment database Environmental Qualification (EQ) data field is a mandatory, design-quality field, and is an accurate record of the PBAPS commitment to 10 CFR 50.49.

2.1.2.4 Maintenance Rule Database

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

2.1.2.5 Design Baseline Documents

System Design Baseline Documents (DBD) are available for selected PBAPS systems. Design Baseline Documents provide detailed descriptions of the associated system design basis, including system functions and design requirements. The system DBD was reviewed, when available, during the system scoping review. Topical Design Baseline Documents are available for topical subjects such as Fire Safe Shutdown, Station Blackout, Electrical Equipment Environmental Qualification Program, Internal Hazards, External Hazards, and Design Basis Accidents, Transients, and Events. These topical DBD's were used in the development of the technical basis documents described in Section 2.1.3.

2.1.2.6 Engineering Drawings

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

2.1.2.7 Controlled Plant Component Database

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

2.1.2.8 Other CLB References

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

Licensing correspondence includes relief requests, Licensee Event Reports, and responses to NRC communications such as NRC bulletins, generic letters, or enforcement actions. Some of these documents may contain licensee commitments.

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

2.1.3 TECHNICAL BASIS DOCUMENTS

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

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

2.1.3.1 License Renewal Systems and Structures List

One of the first steps necessary to begin the second license renewal scoping process was to identify a comprehensive list of plant systems and structures to be evaluated for second license renewal scoping. A basis document was prepared to establish this list and to document the basis for the list. While the Passport equipment database is the primary source for identifying plant systems and structures appropriate for License Renewal consideration, other sources of information were reviewed to validate that all plant systems and structures were identified. The following resources were evaluated for additional information and insight to ensure the list of plant systems and structures is complete: the Peach Bottom UFSAR, plant P&IDs, the first Peach Bottom License Renewal Application (LRA), the Maintenance Rule Database, the Structural Monitoring Program, Peach Bottom site drawings, Peach Bottom Design Baseline Documents, as well as plant walkdowns.

Once the plant systems and structures were identified, each of them was evaluated to determine how to most effectively organize them for second license renewal consideration. In general, plant systems align with license renewal systems at Peach Bottom. However, when a plant system contains components which support the basic function of a different plant system, those components have been administratively realigned to that other system for license renewal purposes. The result of this realignment is the list of second license renewal systems and structures.

Commodity groups were also established to facilitate a focused aging management review process. These commodity groups include hazard barriers and elastomers, component supports, miscellaneous steel, insulation, and other general categories which are common to many systems and structures. This allows for evaluation in one location rather than in each system or structure in which they are applicable.

Once the second license renewal systems and structures are identified, the basis document grouped second license renewal systems and structures into the following categories:

- Reactor Vessel, Internals, and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion System
- Structures and Component Supports
- Electrical and I&C Systems

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

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

2.1.3.2 Identification of Safety-Related Systems and Structures

Safety-related systems and structures are included within the scope of second license renewal in accordance with 10 CFR 54.4(a)(1) scoping criterion. PBAPS plant systems and structures that have been designed to safety-related standards are identified in the UFSAR. PBAPS plant components that have been classified as safety-related are identified as “SR” in the controlled safety classification data field in the Passport equipment database. PBAPS safety classification procedures were reviewed against the second license renewal “Safety-related” scoping criterion in 10 CFR 54.4(a)(1), to confirm that PBAPS safety-related classifications are consistent with second license renewal requirements. This review is included in a technical basis document. The basis document also provides a summary list of the systems and structures that are safety-related at PBAPS. These systems and structures are included within the scope of second license renewal in accordance with the 10 CFR 54.4(a)(1) scoping criterion.

The UFSAR definition of safety-related is as follows:

Safety-related structures, systems, and components are those required to assure:

- *The integrity of the reactor coolant pressure boundary,*
- *The capability to shut down the reactor and maintain it in a safe shutdown condition, or*
- *The capability to prevent, or mitigate the consequences of an accident that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR Part 100 or 10 CFR 50.67 as applicable.*

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

Design Basis Events

The License Renewal Rule 10 CFR 54.4(a)(1) specifically refers to design basis events as defined in 10 CFR 50.49(b)(1), while the PBAPS definition of safety-related is applied to accidents in general terms. For the PBAPS second license renewal project, a separate basis document addresses all design basis accidents and transients that are applicable as defined in 10 CFR 50.49(b)(1). This basis document is also used to answer the 10 CFR 54.4(a)(1) scoping criteria.

Exposure Limits

The guidelines specified in the License Renewal Rule refer to three different Code sections to address similar accident analyses performed by licensees for different reasons: 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), and 10 CFR 100.11.

The guidelines in 10 CFR 50.34(a)(1) are applicable to facilities seeking a construction permit and are therefore not applicable to PBAPS.

The UFSAR Chapter 14 accident analyses were originally performed to address 10 CFR 100 guidelines. Radiological consequence analyses of the design basis accidents were performed to support a full-scope implementation of Alternative Source Term (AST) methodology in accordance with the guidance in Regulatory Guide 1.183 and Standard Review Plan 15.0.1. AST radiological consequence analyses were performed for the four PBAPS design basis accidents that result in offsite exposures. These four accidents are the Loss of Coolant Accident, Main Steam Line Break, Fuel Handling Accident, and Control Rod Drop Accident. The dose consequences for these accidents result in doses that are within the guidelines of 10 CFR 50.67. The AST analytical methods described in Regulatory Guide 1.183 and dose limits defined in 10 CFR 50.67 comprise the design basis for PBAPS design basis accidents.

The PBAPS definition of safety-related is consistent with the 10 CFR 54.4(a)(1) definition for the purposes of identifying the safety-related SSCs that are within the scope of second license renewal. This is consistent with the guidance in NUREG-2192, Section 2.1.3.1.1.

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

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

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

1. Functional (a)(2) - A nonsafety-related system, structure, or component (SSC) that is functionally relied upon in the CLB to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or, (b) directly mitigate the consequences of a Design Basis Event (DBE).

2. Spatial interaction - The effect(s) of nonsafety-related system, structure or component (SSC) failure on a safety-related component, such as pipe whip, jet impingement, general flooding, spray, and displacement/falling.

3. Structural interaction - Occurs in situations where a nonsafety-related piping system physically connects to a safety-related system and the nonsafety-related system is relied upon to provide physical support to the safety-related system up to and including an anchor.

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

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

The basis document describes the PBAPS approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. The basis document provides appropriate guidance to assure that second license renewal scoping for 10 CFR 54.4(a)(2) met the requirements of the second license renewal rule and NEI 95-10. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.5.2.

2.1.3.4 Scoping for Regulated Events

Technical basis documents were prepared to address second license renewal scoping of SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection, Environmental Qualification, Anticipated Transients Without Scram, and Station Blackout. The Commission’s regulations for pressurized thermal shock are not applicable to the PBAPS boiling water reactor design. These basis documents are summarized below:

Fire Protection

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) are included within the scope of second license renewal in accordance with 10 CFR 54.4(a)(3) requirements (Reference 1.7.7).

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

- Systems and structures required to demonstrate post-fire safe shutdown capabilities (FSSD)

- Systems and structures required for fire protection (FP) (detection, suppression, and barriers)

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

The fire detection and suppression systems at PBAPS are plant-wide systems that protect a wide variety of plant equipment. Not all portions of these systems are required to demonstrate compliance with 10 CFR 50.48. Some portions of the fire detection and suppression systems protect plant areas in which a fire would not impact any equipment important to safety or significantly increase the risk of radioactive releases to the environment. Portions of the fire suppression and detection systems are not included within the scope of second license renewal if (1) those portions of the system are provided to protect areas that do not contain any SSCs within the scope of second license renewal and (2) those portions of the system can be isolated from the in scope portions of the system. The portions of the fire suppression and detection systems that are not included within the scope of second license renewal are identified on the Fire Protection System second license renewal boundary drawings in black. Those portions of fire detection and suppression systems that are not included in scope can be isolated from the remaining in scope system by closing the associated isolation valve. The isolation valve is included within the scope of second license renewal.

Environmental Qualification

Criterion 10 CFR 54.4(a)(3) requires that all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for environmental qualification (10 CFR 50.49) be included within the scope of second license renewal (Reference 1.7.8).

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

The environmental qualification basis document summarizes the results of a review of PBAPS EQ program documents. The EQ basis document provides a list of systems that include EQ components. The EQ basis document also provides a list of structures that provide the physical boundaries for the postulated harsh environments, and contain environmentally qualified electrical equipment. These systems and structures are included within the scope of second license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Anticipated Transients Without Scram

Criterion 10 CFR 54.4(a)(3) requires that all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for anticipated transients without scram (10 CFR 50.62) be included within the scope of second license renewal (Reference 1.7.9).

An Anticipated Transient Without Scram (ATWS) is an anticipated operational occurrence that generates an automatic scram signal, accompanied by a failure of the reactor protection system to automatically 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, and to mitigate the consequences of an ATWS event. PBAPS Unit 2 and Unit 3 are boiling water reactors (BWRs). For BWRs, the following requirements apply:

1. Each BWR must have an alternate rod injection (ARI) system with redundant scram air header exhaust valves. The ARI system must be independent of the existing reactor trip system.

2. Each BWR must have a standby liquid control system with defined boron injection capabilities. Standby liquid control system automatic initiation is not required for plants issued a construction permit before July 26, 1984, unless already installed. The PBAPS standby liquid control system is manually initiated.

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

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

- Alternate Rod Insertion (ARI) system features to satisfy the requirements of 10 CFR 50.62(c)(3). The ARI plant system is included in the Control Rod Drive second license renewal system.

- Standby Liquid Control (SLC) system to meet the requirements of 10 CFR 50.62(c)(4).

- ATWS Recirculation Pump Trip (RPT) system to satisfy the requirements of 10 CFR 50.62(c)(5). The ATWS-RPT function is included in the Reactor Recirculation second license renewal system.

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

Station Blackout

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

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

PBAPS satisfies the requirement of 10 CFR 50.63 as an eight-hour coping duration plant with Alternate AC (AAC) Source from the Susquehanna Substation, via a 34.5 kV submarine cable. The Susquehanna Substation receives power from the Conowingo Hydroelectric Plant (Dam). PBAPS capabilities, commitments, and analyses that demonstrate compliance with 10 CFR 50.63 are documented in UFSAR Chapters 8 and 14 and in NRC safety evaluation reports and correspondence related to the SBO rule.

The NUREG-2192 guidance on scoping of equipment relied on to meet the requirements of the SBO rule (10 CFR 50.63) for second license renewal has been incorporated into the PBAPS scoping methodology. In accordance with the NUREG-2192 requirements, the SSCs required to cope with and recover from the SBO event are included within the scope of second license renewal.

Coping is defined as the period of time when the station's offsite sources and on-site ac sources (i.e., emergency diesel generators) are unavailable. Coping assessments are performed for condensate inventory, Class 1E battery capacity, compressed air, loss of ventilation, and containment isolation. As stated above, PBAPS is an eight-hour coping duration plant, and the coping analysis credits an AAC source. Consistent with the first license renewal application and aligned with the second license renewal scoping methodology, the SBO AAC source is included in the scope of second license renewal. The second license renewal boundary for the SBO AAC source was established based on PBAPS current licensing basis. It includes the Conowingo Hydroelectric Plant (Dam); the Susquehanna Substation; the wooden pole adjacent to the Susquehanna Substation; the two associated manholes, one near Conowingo and one at PBAPS; the 34.5 kV submarine cable; the two 34.5 kV inaccessible transition cables, one at each end of the submarine cable; the Station Blackout Substation at PBAPS; and cable connections to the

2SU switchgear which connect to the safety-related buses at PBAPS. These components and commodities are documented as the alternate AC source, in scope components, in NUREG-1769, Safety Evaluation Report (SER) Related to the License Renewal of PBAPS, Section 2.5.1. SER Section 2.5.3 concludes there is reasonable assurance that the applicant has adequately identified the electrical and instrumentation and control SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

Figure 2.1-2 shows the alternate AC source components and the connection to PBAPS safety-related buses.

Recovery is defined as the repowering of the plant AC distribution system from offsite sources or onsite emergency AC sources. In alignment with the second license renewal scoping methodology, for PBAPS station blackout, the boundary between the offsite transmission system and the plant electrical distribution system has been defined for each of the incoming offsite sources.

One power source is an overhead 220 kV transmission line (Cooper-Nottingham line #220-08). The power line is then transitioned from the transmission tower to an outdoor substation bus bar structure, continuing to an in-line disconnect switch, through a 220 kV circuit breaker, and then connects to the 220/13 kV #2 startup transformer. The station blackout boundary between the offsite transmission system and the plant electrical distribution system has been defined at the 220 kV SU-025 circuit breaker.

The second source is an overhead 220 kV transmission system (including Peach Bottom-Newlinville line #220-34) entering the North Substation and transitioning to an outdoor substation bus bar structure. The power line then goes through a 220 kV load interrupter switch and to the 220/13 kV #343 startup transformer. A circuit breaker on the low side of the transformer is also included in the Substations and Transformers system. The station blackout boundary between the offsite transmission system and the plant electrical distribution system has been defined at the 220 kV load interrupter switch on the high side of the 343 SU transformer.

A third source is a 13 kV source tapped off the tertiary windings of the #1 autotransformer. From the tertiary windings the feed goes through a substation bus bar to a 13 kV circuit breaker to the #3 startup and emergency auxiliary regulating transformer. This source can be connected to either Unit 2 or Unit 3 13 kV buses as a second alternative source. The station blackout boundary between the offsite transmission system and the plant electrical distribution system has been defined at the 220 kV #175 circuit breaker, on the 220 kV side of the # 1 autotransformer and at the 500 kV #'s 35 and 45 circuit breakers, on the 500 kV side of the # 1 autotransformer.

This boundary is consistent with NRC standard review plan for second license renewal, NUREG-2192, section 2.5.2.1.1 for the boundary for the Station Blackout recovery path. The NUREG states that the in scope plant system portion of the offsite power system that is used to connect the offsite power source is the equipment out to the first circuit breaker with the offsite distribution system at distribution voltage. This typically includes equipment in the switchyard with the boundary point being a component that operates at transmission system distribution voltage. Control circuits and structures associated with in scope switchyard components are included in the scope for second license renewal. See Figure 2.1-2 for the PBAPS SBO recovery path boundary.

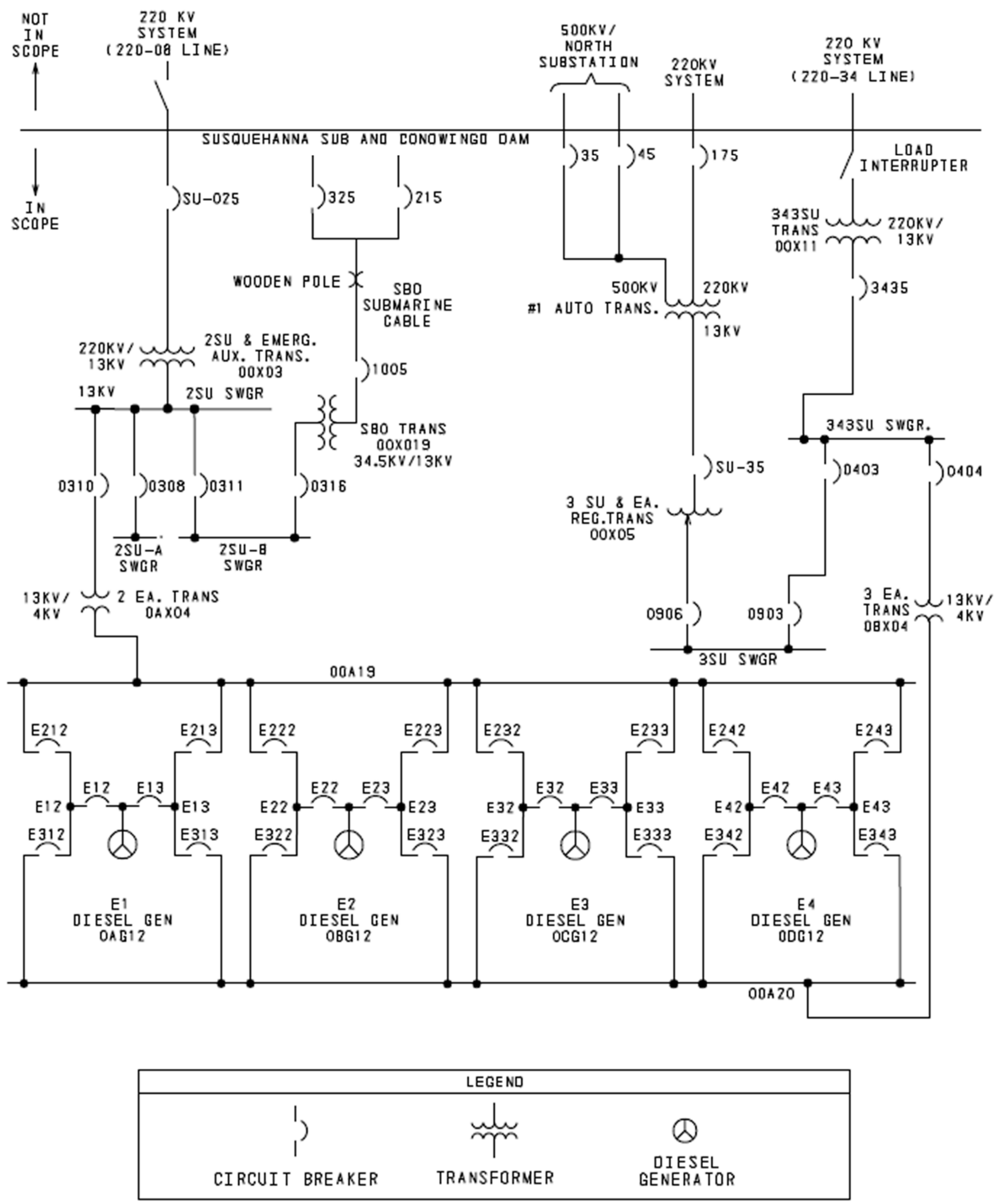
Figure 2.1-2 shows PBAPS connections to the 220 kV and 500 kV transmission system systems. The 220 kV transmission system serves as the preferred and alternate power sources for PBAPS safety-related loads. Two physically independent circuits are provided for each unit.

- The primary source for Unit 2 safety-related loads is via the 2 Startup and Emergency Auxiliary Transformer, the 2SU 13 kV Startup Transformer Switchgear, the 2 Emergency Auxiliary Transformer, the 00A019 metal enclosed bus, and the safety-related Unit 2 4 kV Emergency Auxiliary Switchgear, E12, E22, E32, and E42. The breaker path to 4 kV switchgear E12 is SU-025, 0310, and E212. The 00A019 metal enclosed bus is also connected to the Unit 3, 4 kV Emergency Auxiliary Switchgear E13, E23, E33, and E43. This path from the 2 Startup and Emergency Auxiliary Transformer to the 00A019 metal enclosed bus serves as the alternate offsite source to Unit 3 safety-related loads. The breaker path to 4 kV switchgear E13 is SU-025, 0310, and E213.
- The primary source for Unit 3 safety-related loads is via the 343 Startup Transformer, the 343 Startup Transformer Switchgear, the 3 Emergency Auxiliary Transformer, the 00A020 metal enclosed bus, and the safety-related Unit 3 4 kV Emergency Auxiliary Switchgear, E13, E23, E33, and E43. The breaker path to 4 kV switchgear E13 is Load Interrupter, 3435, 0404, and E313. The 00A020 metal enclosed bus is also connected to the Unit 2, 4 kV Emergency Auxiliary Switchgear E12, E22, E32, and E42. This path from the 343 Startup Transformer to the 00A020 metal enclosed bus serves as the alternate offsite source to Unit 2 safety-related loads. The breaker path to 4 kV switchgear E12 is Load Interrupter, 3435, 0404, and E312.

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

Figure 2.1-2

PEACH BOTTOM SBO ALTERNATE AC SOURCE AND RECOVERY PATH BOUNDARIES



2.1.4 INTERIM STAFF GUIDANCE DISCUSSION

There are no ISG's applicable to PBAPS second license renewal.

2.1.5 SCOPING PROCEDURE

The scoping process is the systematic approach used to identify the PBAPS systems, structures, and components within the scope of second license renewal. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions were identified from a review of the source CLB documents and the first license renewal application. In scope boundaries were established and documented in the system and structure scoping reports, based on the identified intended functions. The in scope boundaries form the basis for identification of the in scope components, which is the first step in the screening process described in Section 2.1.6. The system and structure scoping results are provided in Section 2.2.

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

- Reactor Vessel, Internals, and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion System
- Structures and Component Supports
- Electrical and I&C Systems

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

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

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

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

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

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

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

Safety-related classifications for systems and structures are based on system and structure descriptions and analyses in the UFSAR, or on design basis documents such as engineering drawings, design specifications, evaluations, or calculations. Systems and structures that are identified as safety-related in the UFSAR or in design basis documents have been classified as satisfying the criteria of 10 CFR 54.4(a)(1) and have been included within the scope of second license renewal. Safety-related components listed in the Passport equipment database were also reviewed and the system or structure associated with the safety-related component was included within the scope of second license renewal in accordance with 10 CFR 54.4(a)(1) criteria. The review also confirmed that Anticipated Operational Occurrences (AOOs), Abnormal Operating Transient (AOTs), Design Basis Accidents (DBAs), External Hazards, Internal Events, and Special Events as described in the current licensing basis (CLB), were considered for second license renewal scoping.

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

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

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

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

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

Each of these three categories is discussed below:

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

This category addresses nonsafety-related SSCs that are required to function in support of a safety-related SSC intended function. The functional requirement distinguishes this category from the other categories, where the nonsafety-related SSCs are required only to maintain adequate integrity to preclude structural failure or spatial interactions. The nonsafety-related SSCs that were included within the scope of second license renewal to functionally support a safety-related SSC in performing a 10 CFR 54.4(a)(1) intended function are identified on the second license renewal boundary drawings in green.

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

- The Cranes and Hoists System includes nonsafety-related cranes, hoists and refueling equipment that provide a safe means for handling loads above or near safety-related components or spent fuel.

- The Fuel Pool Cooling and Cleanup System includes nonsafety-related piping components between the fuel pools and the RHR System in support of the RHR System intended function to provide adequate cooling for spent fuel.

- The Main Condenser System includes the nonsafety-related main condenser that provides for post accident containment holdup of MSIV bypass leakage.

- The Main Steam System includes nonsafety-related main steam lines that are credited with holdup and plateout of MSIV leakage following a LOCA. Routing of the MSIV leakage through nonsafety-related main steam line drains to the main condenser permits additional plateout and holdup in the main condenser.

- The Neutron Monitoring System includes nonsafety-related SSCs that are credited for mitigating a rod withdrawal error.

- The Plant Equipment and Floor Drain System includes nonsafety-related floor drains located in the Circulating Water Pump Structure High Pressure Service Water (HPSW) and Emergency Service Water (ESW) pump compartments and the Circulating Water Pump Structure sump pumps that are credited to mitigate internal flooding of the HPSW and ESW pumps compartments.

- The Radiation Monitoring System includes nonsafety-related SSCs that monitor for radiation level and initiate appropriate protective action to limit the potential release of radioactive materials if predetermined levels are exceeded.

- The Reactor Manual Control System includes nonsafety-related SSCs that support the control rod drop accident analysis and refueling interlocks for a rod withdrawal error during refueling and heavy loads analysis.

- Nonsafety-related thermal insulation on piping components prevents excessive localized and general area temperatures from causing failure of safety-related SSCs. Thermal insulation systems are designed to prevent the intrusion of moisture, which if allowed to accumulate under the insulation, could result in accelerated corrosion of the insulated safety-related component.

These nonsafety-related systems, or nonsafety-related portions of safety-related systems, were included within the scope of second license renewal in accordance with 10 CFR 54.4(a)(2).

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

The next two 10 CFR 54.4(a)(2) scoping categories are the subject of NEI 95-10, Appendix F, as referred to in NEI 17-01. The guidance requires that, when demonstrating that failures of nonsafety-related systems would not adversely impact the ability to maintain intended functions, a distinction must be made between nonsafety-related systems that are directly connected to safety-related systems and provide support for safety-related SSCs, and those that are not directly connected to safety-related systems and have the potential for spatial interactions with safety-related SSCs. The methodology as described below for the identification of PBAPS SSCs that satisfy the 10 CFR 54.4(a)(2) scoping criterion was based on a review of applicable CLB documents, as well as plant-specific and industry operating experience.

Connected to and Provide Structural Support for Safety-Related SSCs

For nonsafety-related SSCs directly connected to safety-related SSCs the nonsafety-related piping and supports, up to and including the first seismic or equivalent anchor (such as a series of 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 (3) orthogonal directions) beyond the safety/nonsafety interface, are within the scope of second license renewal per 10 CFR 54.4(a)(2). The “first seismic or equivalent anchor” is defined such that the failure in the nonsafety-related pipe run beyond the first seismic or equivalent anchor will not render the safety-related portion of the piping unable to perform its intended function under CLB design conditions.

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

a) A combination of restraints or supports that encompasses at least two (2) supports in each of three (3) orthogonal directions.

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

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

d) A free end of nonsafety-related piping, such as a drain pipe that ends at an open floor drain.

e) For nonsafety-related piping runs that are connected at both ends to safety-related piping, the entire run of nonsafety-related piping is included in scope.

f) A point where buried piping exits the ground. The buried portion of the piping should be included in the scope of second license renewal. A determination that the buried piping is well founded on compacted soil that is not susceptible to liquefaction must be documented.

g) A smaller branch line where the moment of inertia ratio of the larger piping to the smaller piping is equal to or greater than the acceptable ratio defined by the current licensing basis, because significantly smaller piping does not impose loads on larger piping and does not support larger piping. The moment of inertia ratio used was 3 to 1.

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

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

Potential for Spatial Interactions with Safety-Related SSCs

Nonsafety-related systems that are not connected to safety-related piping or components, or are outside the structural support boundary for the attached safety-related piping system, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be evaluated for second license renewal scope in accordance with 10 CFR 54.4(a)(2) requirements. The structures of concern for potential spatial interaction were identified based on a review of the CLB to determine which structures contained active or passive safety-related SSCs. Plant walkdowns were performed, as required, to confirm that all structures containing safety-related SSCs were identified.

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

Mitigative Option: The mitigative option involves crediting plant mitigative features to protect safety-related SSCs from failures of nonsafety-related SSCs. Plant mitigative features considered include pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, and physical barriers (e.g., floors, walls, doors, conduit). This option requires a demonstration that the mitigating features are adequate to protect safety-related SSCs from failures of nonsafety-related SSCs regardless of failure location. If this level of protection can be demonstrated, then only the mitigative features need be included within the scope of second license renewal. The mitigative option was used for scoping systems located in the turbine building portion of the Turbine Building and Main Control Room Complex, the Yard Structures, and the Radwaste Building and Reactor Auxiliary Bay since these structures have few areas containing safety-related SSCs. Where possible, mitigative features were used to prevent spatial interaction between safety-related SSCs and nonsafety-related SSCs within these structures. No credit was taken for separation by distance alone without a mitigative feature capable of preventing the spatial interaction. The mitigative features were included in the scope of second license renewal. In certain areas of these structures it was not possible to credit mitigative features. In these areas the preventive option was used as described below. This evaluation was documented in a technical basis document.

Preventive Option: The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function, and including the identified nonsafety-related SSC within the scope of second license renewal without consideration of plant mitigative features. The preventive option was used for scoping systems located in the Reactor Building Structure, Containment Structure, Diesel Generator Building, Circulating Water Pump Structure (safety-related portion), Nitrogen Storage Building, Emergency Cooling Tower and Reservoir, Stack, and the main control room complex portion of the Turbine Building and Main Control Room Complex (includes the main control room, cable spreading room, 4kV switchgear rooms, and battery rooms). All liquid filled nonsafety-related SSCs located in these structures were assumed to be located in proximity to safety-related SSCs where potential spatial interaction could occur, and were therefore included in scope. The preventive option was also used in the turbine building portion of the Turbine Building and Main Control Room Complex, the Yard Structures, and the Radwaste Building and Reactor Auxiliary Bay in areas where mitigative features were not credited to prevent spatial interaction.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, are included in scope for potential spatial interaction under criterion 10 CFR 54.4(a)(2), unless, as described above, they are located in an area where there is no concern with spatial interaction due to crediting plant mitigative features. High-energy lines (normal operating service conditions above 200 deg F and above 275 psig) with potential spatial interaction are included in the scope of second license renewal under 10 CFR 54.4(a)(1) or (a)(2) depending on their safety classification. Safety-related high-energy lines are in scope under 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines are in scope under 10 CFR 54.4(a)(2). Potential spatial interaction due to leakage or spray is assumed for moderate/low-energy liquid systems (normal operating service conditions less than or equal to 200 deg F or less than or equal to 275 psig) for system pressure as low as atmospheric.

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

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

Scoping of Abandoned Equipment

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

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

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

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

The regulation for pressurized thermal shock (10 CFR 50.61) is applicable to pressurized water reactors only, and therefore not applicable to PBAPS which is a boiling water reactor. For each of the other four regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event basis documents (described in Section 2.1.3.4) identify the systems and structures that are relied upon to demonstrate compliance with the applicable regulation. The basis documents also identify the source documentation used to determine the scope of components within the system that are credited to demonstrate compliance with each of the applicable regulated events. Guidance provided by the technical basis documents was incorporated into the system and structure scoping evaluations, to determine the SSCs credited for each of the regulated events. SSCs credited in the regulated events have been classified as satisfying criteria of 10 CFR 54.4(a)(3) and have been included within the scope of second license renewal.

2.1.5.4 System and Structure Intended Functions

For the systems and structures within the scope of second license renewal, the intended functions that are the bases for including them within the scope of second license renewal are identified and documented in the scoping evaluation. The system or structure intended functions are based on the applicable CLB reference documents. For systems, the system level intended function descriptions associated with 10 CFR 54.4(a)(1) were standardized based on nuclear safety criteria for boiling water reactors as documented in industry standard ANSI/ANS-52.1-1983. The use of standardized 10 CFR 54.4(a)(1) functions provided for consistent function application and appropriate level of detail for system level intended function descriptions. The component level intended functions are the passive component functions that are necessary to support the system or structure intended function(s). The structure and component intended functions are further described in Section 2.1.6.2.

2.1.5.5 Scoping Boundary Determination

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

Mechanical Systems

For mechanical systems, the mechanical components that support the system intended functions are included within the scope of second license renewal and are depicted on the applicable system piping and instrumentation diagram.

Mechanical system piping and instrumentation diagrams are marked up to create second license renewal boundary drawings showing the in scope passive components. Components that are required to perform or support a safety-related function, or a function that demonstrates compliance with one of the second license renewal regulated events, are identified on the system piping and instrumentation diagrams by green lines. Nonsafety-related components that are connected to safety-related components and are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function due to spatial interaction with safety-related SSCs, are identified by red lines. A computer sort and download of associated system components from the equipment database confirms the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

Structures

For structures, the structural components that support the intended functions are included in the scope of second license renewal. The structural components are identified from a review of applicable plant design drawings of the structure, applicable UFSAR sections, and design basis documentation. Plant walkdowns were performed when required for additional confirmation. Structural bolting required to support the structure proper is evaluated with the structure. Structural bolting supporting the intended function of a component support or a structural commodity component is evaluated with the component support or structural commodity component. A site plan layout drawing is marked up to create a second license renewal boundary drawing showing the structures within the scope of second license renewal in green.

Electrical Systems

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

2.1.6 SCREENING PROCEDURE

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

2.1.6.1 Identification of Structures and Components Subject to AMR

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

Each application must contain the following information:

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

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

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

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

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

NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" and NEI 95-10, Appendix B, as referred to in NEI 17-01, were used as the basis for the identification of passive structures and components. Most passive structures and components are long-lived. In the few cases where a passive component is determined not to be long-lived, such determination is documented in the screening evaluation and, if applicable, on the associated second license renewal boundary drawing.

The PBAPS structures and components subject to aging management review have been identified in accordance with the requirements of

10 CFR 54.21(a)(1) described above. The process implemented to meet these requirements for mechanical systems, structures, and electrical commodities is described as follows:

Mechanical Systems

The mechanical system screening process began with the results from the scoping process. For in scope mechanical systems, the completed scoping packages include written descriptions and marked up system piping and instrumentation diagrams that clearly identify the in scope system boundary for second license renewal. The marked up system piping and instrumentation diagrams are called second license renewal system boundary drawings. These system boundary drawings were reviewed to identify the passive, long-lived components and component types. Component listings from the Passport equipment database were also reviewed to confirm that all system components were considered. In cases where the system piping and instrumentation diagram did not provide sufficient detail, such as for some large vendor supplied components (e.g., compressors, emergency diesel generators), the associated component drawings or vendor manuals were also reviewed. Plant walkdowns were performed when required for confirmation.

Some mechanical components, when combined, are considered a complex assembly. A complex assembly is a predominantly active assembly where the performance of its components is closely linked to that of the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of these components. An example of a complex assembly are the diesel generators. Complex assemblies are considered active and can be excluded from the requirements of AMR. However, to the extent that complex assemblies include piping or components that interface with external equipment, or components that cannot be adequately tested or monitored as part of the complex assembly, those components are identified and subject to aging management review. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants”.

Mechanical components are screened with the system in which they were scoped. For heat exchangers, the process side of the heat exchanger is evaluated with the process side system for aging management review. Likewise, the cooling water side of the heat exchanger is evaluated with the cooling water side system for aging management review.

Structures

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

Electrical Commodities

Screening of electrical and I&C components within the in scope electrical, I&C, and mechanical systems used a bounding approach as described in NEI 17-01. Electrical and I&C components for the in scope systems were assigned to commodity groups. The commodities subject to an aging management review are identified by applying the criteria of 10 CFR 54.21(a)(1). This method provides the most efficient means for determining the electrical commodities subject to an aging management review since many electrical and I&C components and commodities are active.

Electrical and I&C components such as elements, resistance temperature detectors (RTDs), sensors, thermocouples, and transducers as well as electric heaters primarily serve an electrical function; however, they can also serve a mechanical pressure boundary function. According to Appendix B of NEI 95-10, as referred to in NEI 17-01, the electrical portions of these components are active per 10 CFR 54.21(a)(1)(i) and are therefore not subject to aging management review. Only the pressure boundary of such an in scope component is subject to aging management review.

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

1. Electrical and I&C components and commodities in systems within the scope of second license renewal at PBAPS were identified and listed. The listing provided by NUREG-2192, Table 2.1-6, is the basis for this list. Electrical and I&C components and commodities were organized into groups such as circuit breakers, switches, and cables. Individual specific components were not identified. The electrical commodities were identified from a review of plant documents, controlled drawings, the Passport equipment database, and interface with the parallel mechanical screening efforts.

2. Following the identification of the electrical commodities, the criterion of 10 CFR 54.21(a)(1)(i) was applied to identify commodities that perform their functions without moving parts or without a change in configuration or properties (referred to as “passive” components). These commodities were identified utilizing the guidance of NUREG-2192, Table 2.1-6.

3. The passive electrical commodities were reviewed to determine if the commodity performs a license renewal intended function. If an electrical commodity does not perform a license renewal intended function, it was not considered further and, therefore, is not subject to an aging management review.

4. The screening criterion found in 10 CFR 54.21(a)(1)(ii) excludes those commodities that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to those commodities that were not previously eliminated by the application of the 10 CFR 54.21(a)(1)(i) screening criterion. Components and

commodities included in the plant environmental qualification (EQ) program are replaced on a specified interval based on a qualified life. Components and commodities in the EQ program do not meet the “long-lived” criterion of 10 CFR 54.21(a)(1)(ii) and are considered “short-lived” per the regulatory definition and are, therefore, not subject to an aging management review.

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

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

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

Conowingo Hydroelectric Plant (Dam)

The offsite Conowingo Hydroelectric Plant (Dam) is owned and operated by Exelon Generation and is licensed by the Federal Energy Regulatory Commission (FERC). Screening of Conowingo was performed at the plant (dam) level. Aging management of Conowingo will be performed during the second period of extended operation based on current licensing basis established for Peach Bottom in NUREG-1769, Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3, Section 3.6.3 “Station Blackout System”. The staff concluded as stated in paragraph 3.6.3.2.1 “Aging Management Program”, “By virtue of the FERC’s authority and responsibility for ensuring that its regulated projects are constructed, operated, and maintained to protect life, health, and property, the staff finds that for earthen embankments, dams, appurtenances, and related structures subject to AMR, continued compliance with FERC requirements during the license renewal period will constitute an acceptable dam aging management program for the purposes of license renewal. Therefore, the staff finds the program acceptable.” PBAPS will continue to comply with these FERC requirements during the second period of extended operation.

2.1.6.2 Intended Function Definitions

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

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

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Intended Function	Definition
Absorb Neutrons	Absorb neutrons.
Direct Flow	Provide spray shield or curbs for directing flow, which may include protective features for medium energy line breaks (MELB). Also applies to diffusers credited for fluid diffusion/dissipation, e.g., HVAC diffusers.
Electrical Continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.
Expansion/Separation	Provide for thermal expansion and/or seismic separation.
Filter	Provide filtration or foreign material exclusion.
Fire Barrier	Provide rated fire barrier to confine or retard fire from spreading to or from adjacent areas of the plant.
Flood Barrier	Provide flood protection barrier (internal and external flood event). This may include protective features for medium energy line breaks (MELB).
Gaseous Release Path	Provide path for release of filtered and unfiltered gaseous discharge
Heat Transfer	Provide heat transfer.
HELB/MELB Shielding	Provide shielding against high energy line breaks (HELB), and protective features for medium energy line breaks (MELB).
Holdup	Provide post accident containment, holdup (for radioactive decay) of iodine and non-condensable gases before release.
Holdup and Plateout	Provide post accident containment, plateout of iodine and holdup (for radioactive decay) of iodine and non-condensable gases before release.
Insulate (Electrical)	Insulate and support an electric conductor.
Leakage Boundary	Nonsafety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. This function includes the required structural integrity when the nonsafety-related leakage boundary piping is also attached to safety-related piping.
Maintain Adhesion	Provides adhesion to the substrate.

Table 2.1-1 Passive Structure and Component Intended Function Definitions

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

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Intended Function	Definition
Throttle	Provide flow restriction.
Water retaining boundary	Provide an essentially leak-tight boundary.

2.1.6.3 Stored Equipment

Credit is taken for actions required to restore operability to FSSD equipment which has failed as a result of fire-induced damage. In all cases, such credit is taken only to accomplish a function required for cold shutdown. Equipment that is stored on site for installation or use in achieving cold shutdown is considered to be within the scope of license renewal. For each repair credited, a procedure has been written and is available to cover the repair, and, the quantity and specific type of materials required by the analysis and the procedure are stored onsite. Stored equipment may also be used as directed by emergency operating procedures. Periodic surveillances are performed to verify that the equipment and materials are at the designated location, in the quantity specified, and in good condition and capable of performing the intended function. Tools and supplies used to place the stored equipment in service are not within the scope of license renewal.

2.1.6.4 Consumables

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

- Group (a) subcomponents (packing, gaskets, component seals, and O-rings): Managing loss of leak tightness due to degraded packing, gaskets, component seals, and O-rings for the pressure boundary and leakage boundary intended functions is not required. It is unlikely that leakage from packing, gaskets, component seals, and O-rings would result in failure of the system to deliver sufficient flow at adequate pressure. In regard to leakage, PBAPS routinely conducts tours of the operating spaces. When leakage is detected it is entered into the corrective action program. The leakage is corrected by replacing the packing, gaskets, component seals, and O-rings as consumables.
- Group (b) structural sealants: AMRs were required for structural sealants in structures within the scope of second license renewal. A summary of the AMR results is presented in Section 3.5.
- Group (c) subcomponents (oil, grease, and component filters): These subcomponents are short-lived and are periodically replaced. Various plant procedures are used in the replacement of oil, grease, and filters in components that are in scope for second license renewal. Therefore, these subcomponents are not subject to an AMR.
- Group (d) consumables (system filters, fire extinguishers, fire hoses, and air packs): System ventilation filters are replaced in accordance with plant procedures based on vendor manufacturers' requirements and system testing. Fire extinguishers, self-contained breathing air packs and fire hoses are within the scope of license renewal, but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with NFPA

10 for portable fire extinguishers, ANSI Z88.2-1992 for self-contained breathing air packs, and NFPA 1962 for fire hoses. These require replacement of equipment based on their condition or performance during testing and inspection. The periodic inspections are implemented by controlled PBAPS procedures. These components are subject to replacement based on requirements implemented by controlled procedures, and are therefore not long-lived and not subject to an aging management review.

2.1.7 GENERIC SAFETY ISSUES

In accordance with the guidance in NEI 17-01 and Appendix A.3 of NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” review of NRC generic safety issues (GSIs) as part of the second license renewal process is required to satisfy 10 CFR 54.29. This guidance suggests that GSIs involving issues related to second license renewal aging management reviews or TLAAs should be addressed in the second license renewal application. Based on Nuclear Energy Institute (NEI) and NRC guidance, NUREG-0933 “Resolution of Generic Safety Issues,” Supplement 34 (Reference 1.7.15), and more recent NRC Generic Issue Management Control System Reports, the following GSIs are addressed for PBAPS second license renewal:

- GSI 186, Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants - This GSI addresses heavy load issues related to crane design and operation. Aging effects are not central to these issues. The issue does not involve time-limited aging analyses, including typical crane-related TLAAs such as cyclic loading analyses. This issue is now closed. (Reference ML120940306)

- GSI-189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion During a Severe Accident - This issue is not applicable to PBAPS. PBAPS does not have an Ice Condenser Containment. This issue is now closed. (Reference ML13190A237)

- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance - This issue is not applicable to PBAPS. PBAPS is a BWR.

- GSI-193, BWR ECCS Suction Concerns - The Generic Issues Review Panel completed an assessment and found this issue does not present a significant safety hazard. No further regulatory actions are required. This issue is now closed. (Reference ML16207A507)

- GSI-199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States for Existing Plants - This GSI addresses how current estimates of the seismic hazard level at some nuclear sites in the central and eastern United States might be higher than the values used in their original designs and previous evaluations. Aging effects are not central to this issue. This issue does not involve time-limited aging analyses. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations. (Reference ML16102A368)

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

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

2.1.8 CONCLUSION

The scoping and screening methodology described above was used for the PBAPS IPA to identify the systems, structures, and components that are within the scope of second license renewal and that are subject to an aging management review. The methodology is consistent with and satisfies the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 PLANT LEVEL SCOPING RESULTS

Table 2.2-1 lists the Peach Bottom Atomic Power Station (PBAPS) systems, structures and commodity groups that were evaluated to determine if they were within the scope of license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in scope system, structure and commodity group in the Table.

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Reactor Vessel, Internals, and Reactor Coolant System		
Reactor Pressure Vessel and Internals System	Yes	2.3.1.1
Reactor Pressure Vessel Instrumentation System	Yes	2.3.1.2
Reactor Recirculation System	Yes	2.3.1.3
Fuel Assemblies	Yes	2.3.1.4
Engineered Safety Features		
Containment Atmosphere Control and Dilution System	Yes	2.3.2.1
Core Spray System	Yes	2.3.2.2
High Pressure Coolant Injection System	Yes	2.3.2.3
Primary Containment Isolation System	Yes	2.3.2.4
Reactor Core Isolation Cooling System	Yes	2.3.2.5
Residual Heat Removal System	Yes	2.3.2.6
Secondary Containment System	Yes	2.3.2.7
Standby Gas Treatment System	Yes	2.3.2.8
Auxiliary Systems		
Auxiliary Steam System	Yes	2.3.3.1
B.5.b Equipment	No	None
Backup Instrument Nitrogen to ADS System	Yes	2.3.3.2
Battery and Emergency Switchgear Ventilation System	Yes	2.3.3.3
Chilled Water System	Yes	2.3.3.4
Circulating Water System and Cooling Towers	No	UFSAR 11.6
Condensate Transfer System	Yes	2.3.3.5

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Control Rod Drive System	Yes	2.3.3.6
Control Room Ventilation System	Yes	2.3.3.7
Cranes and Hoists System	Yes	2.3.3.8
Diesel Generator Building Ventilation System	Yes	2.3.3.9
Domestic Water System	Yes	2.3.3.10
Drywell Ventilation System	No	UFSAR 5.2.3.7
Emergency Cooling Water System	Yes	2.3.3.11
Emergency Diesel Generator System	Yes	2.3.3.12
Emergency Eyewash and Showers System	No	None
Emergency Service Water System	Yes	2.3.3.13
Fire Protection System	Yes	2.3.3.14
FLEX Equipment	No	None
Fuel Handling System	Yes	2.3.3.15
Fuel Pool Cooling and Cleanup System	Yes	2.3.3.16
High Pressure Service Water System	Yes	2.3.3.17
Hydrogen Water Chemistry System	No	UFSAR 9.4.4.5
Hypochlorite System	No	None
Instrument Air System	No	UFSAR 10.17
Instrument Nitrogen System	No	UFSAR 10.17
Miscellaneous Mechanical Components System	No	None
Miscellaneous Ventilation Systems	No	UFSAR 10.15
Offgas and Recombiner System	Yes	2.3.3.18

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Plant Equipment and Floor Drain System	Yes	2.3.3.19
Post Accident Sampling System	Yes	2.3.3.20
Primary Containment Leak Test System	No	UFSAR 5.2
Process Sampling System	Yes	2.3.3.21
Pump Structure Ventilation System	Yes	2.3.3.22
Radiation Monitoring System	Yes	2.3.3.23
Radwaste Building Ventilation System	No	UFSAR 10.15
Radwaste System	Yes	2.3.3.24
Reactor Building Closed Cooling Water System	Yes	2.3.3.25
Reactor Building Ventilation System	No	UFSAR 10.14
Reactor Water Cleanup System	Yes	2.3.3.26
Refueling Water Storage and Transfer System	Yes	2.3.3.27
Safety Grade Instrument Gas System	Yes	2.3.3.28
Security System	No	None
Service Air System	No	UFSAR 10.17
Service Water Bay Chemical Injection System	No	None
Service Water System	Yes	2.3.3.29
Sewage Treatment System	No	UFSAR 10.18
Standby Liquid Control System	Yes	2.3.3.30
Suppression Pool Temperature Monitoring System	Yes	2.3.3.31
Torus Water Cleanup System	Yes	2.3.3.32
Torus Water Storage and Transfer System	Yes	2.3.3.33

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Traveling Water Screen System	Yes	2.3.3.34
Traversing In Core Probe System	No	UFSAR 7.5.9
Turbine Building Closed Cooling Water System	Yes	2.3.3.35
Turbine Building Ventilation System	No	UFSAR 10.15
Water Treatment System	Yes	2.3.3.36
Steam and Power Conversion System		
Condensate System	Yes	2.3.4.1
Condensate Storage System	Yes	2.3.4.2
Feedwater System	Yes	2.3.4.3
Main Condenser System	Yes	2.3.4.4
Main Steam System	Yes	2.3.4.5
Turbine-Generator System	No	UFSAR 4.11
Structures and Component Supports		
Adjustable Speed Drive Power Distribution Center Building	No	Comment 1
Administration Building and Shop	Yes	2.4.1
Boiler House	Yes	2.4.2
Bridge Structure	No	Comment 2
Circulating Water Pump Structure	Yes	2.4.3
Component Supports	Yes	2.4.4
Containment Structure	Yes	2.4.5
Cooling Tower Pump Structures	No	Comment 3
Cooling Towers	No	Comment 4

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Dewatering Building	Yes	2.4.6
Diesel Generator Building	Yes	2.4.7
Discharge Control Structure	No	Comment 5
Electrical and Instrumentation Enclosures and Raceways	Yes	2.4.8
Emergency Cooling Tower and Reservoir	Yes	2.4.9
FLEX Storage Building	No	Comment 6
Guardhouse	No	Comment 7
Hazard Barriers and Elastomers	Yes	2.4.10
Independent Spent Fuel Storage Installation	No	Comment 8
Insulation	Yes	2.4.11
Intake Screen Structure	No	Comment 9
Meteorological Towers	No	Comment 10
Miscellaneous Steel	Yes	2.4.12
Nitrogen Storage Building	Yes	2.4.13
Off-Gas Filter Station	No	Comment 11
Outdoor Electric Switchgear, North Substation	Yes	2.4.14
Plant Entrance and Radiochemistry Laboratory	No	Comment 12
Plant Services Building	No	Comment 13
Radwaste Building and Reactor Auxiliary Bay	Yes	2.4.15
Radwaste Onsite Storage Facility	No	Comment 14
Reactor Building	Yes	2.4.16
Recombiner Building	Yes	2.4.17

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Secondary Alarm Station Building	No	Comment 15
Sewage Treatment Structures	No	Comment 16
Site Management Building	No	Comment 17
Stack	Yes	2.4.18
Station Blackout Structure and Foundations	Yes	2.4.19
Turbine Building and Main Control Room Complex	Yes	2.4.20
Unit 1 and Training Building	No	Comment 18
Warehouse Complex	No	Comment 19
Water Treatment Building	No	Comment 20
Watertight Dikes	Yes	2.4.21
Yard Structures (Manholes, Duct Banks, Valve Pits, etc.)	Yes	2.4.22
Electrical and I&C Systems		
13 KV System	Yes	UFSAR 8.4
4 kV System	Yes	UFSAR 8.4
480 Volt Emergency Load Centers System	Yes	UFSAR 8.4.2
480 Volt Emergency Motor Control Center System	Yes	UFSAR 8.4
480 Volt Load Center System	No	UFSAR 8
480 Volt Motor Control Center System	No	UFSAR 8
Annunciator System	No	None
Cathodic Protection System	No	None
Communications System	Yes	UFSAR 10.21
Computer System	No	UFSAR 7.16

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
DC System	Yes	UFSAR 8.7
Electrical Commodities	Yes	2.5.2.5
Electrical Heat Tracing System	No	None
Fire Safe Shutdown System	Yes	Fire Protection Program
Instrument AC System Panels	Yes	UFSAR 8.6
Meteorology System	No	UFSAR 2.3.3
Neutron Monitoring System	Yes	UFSAR 7.5
Reactor Manual Control System	Yes	UFSAR 7.7
Reactor Protection System	Yes	UFSAR 7.2
Remote Shutdown Panel System	Yes	UFSAR 7.18
RPS - MG Set and Alternate Feed System	No	UFSAR 7.2.3.2
Seismic Monitoring System	No	UFSAR 7.1.1
Station Blackout System	Yes	UFSAR 8.1
Station Lighting System	No	UFSAR 10.22
Substations and Transformers	Yes	UFSAR 8.3

Comments:

Evaluation of the following structures determined that they do not perform an intended function and are not in scope for license renewal:

1. The Adjustable Speed Drive Power Distribution Center Building supports and houses nonsafety-related Unit 3 ASD Power Distribution Center Components, and provides support for nonsafety-related Unit 2 ASD heat exchangers and associated components. The Adjustable Speed Drive Power Distribution Center Building consists of the Unit 2 ASD heat exchanger steel frame support structure located on the west side of the Radwaste Building, and the Unit 3 ASD Power Distribution Center and supports located northwest of the Unit 3 Torus Water Storage Tank. The Adjustable Speed Drive Power Distribution Center Building is classified as non-safety-related and is separated from safety-related

systems and structures or shown by analysis that its failure would not impact a safety-related function.

2. The Bridge Structure provides a crossing of the discharge canal for access to the circulating water system Cooling Towers. The bridge is located southeast of the plant in the discharge canal area. The Bridge Structure is nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

3. The Cooling Tower Pump Structures provide support, shelter and protection for the seismic Class II cooling tower pumps, which pump water to the circulating water system cooling towers that limit the temperature of cooling water discharged to the Conowingo Pond. The Cooling Towers and Cooling Tower Pump Structures are located south-southeast of the Circulating Water Pump Structure on filled land in the Conowingo Pond. The Cooling Tower Pump Structures are seismic Class II and nonsafety-related. The Cooling Tower Pump Structures are classified as nonsafety-related and are separated from safety-related systems and structures such that failures would not impact a safety-related function.

4. The Cooling Towers are provided to limit the temperature of cooling water discharged to the Conowingo Pond. The Cooling Towers are located south-southeast of the Circulating Water Pump Structure on filled land in the Conowingo Pond. The Cooling Towers are seismic Class II and nonsafety-related. The Cooling Towers are classified as nonsafety-related and are separated from safety-related systems and structures such that their failure would not impact a safety-related function.

5. The Discharge Control Structure provides control of the level of discharge water within cooling dikes and provides for the discharge of water to the Conowingo Pond. The Discharge Control Structure is located south-southeast of the intake structure on filled land in the Conowingo Pond. The Discharge Control Structure is Seismic Class II and nonsafety-related. The Discharge Control Structure is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

6. The FLEX Storage Building is a robust building that provides for storage of equipment associated with FLEX coping strategies. The building is located outside the protected area in the upper parking facility east of the Radwaste Onsite Storage Facility. The FLEX Storage Building is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

7. The Guardhouse provides control of personnel access into the protected area. The Guardhouse is located northeast of the turbine building. The Guardhouse is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

8. The Independent Spent Fuel Storage Facility provides for storage of spent fuel housed in dry storage casks. The facility is located on the south of the plant, outside of the plant's protected area boundary. It is enclosed in its own protected area boundary. The facility is licensed under a separate regulation 10 CFR Part 72, and therefore, is outside the scope of 10 CFR Part 54. The Independent Spent Fuel Storage Facility is classified as nonsafety-related and is separated from safety-related systems and structures such that failures would not impact a safety-related function.

9. The Intake Screen Structure provides housing for 24 traveling water screens protected by bar racks. The structure is located on the outer dike embankment which is off-shore in the Conowingo Pond. The Conowingo Pond and the Intake Screen Structure are not required for emergency heat sink operation. The Intake Screen Structure is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

10. The Meteorological Towers provide support for instruments that provide information to the meteorological monitoring program. The site is equipped with two meteorological towers. The Meteorological Towers are classified as nonsafety-related and are separated from safety-related systems and structures such that failure would not impact a safety-related function.

11. The Off-Gas Filter Station provides housing for the off-gas filters. The station is partially buried in the side of the slope south of the Unit 2 Turbine Building. The Off-Gas Filter Station is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

12. The Plant Entrance and Radiochemistry Laboratory provides an entrance area for control of personnel into the plant and a radiochemistry laboratory facility. The Plant Entrance and Radiochemistry Laboratory is located north of the nonsafety-related Unit 3 Turbine Building. The Plant Entrance and Radiochemistry Laboratory are classified as nonsafety-related and are separated from safety-related systems and structures such that its failure would not impact a safety-related function of adjacent structures.

13. The Plant Services Building provides housing for site work groups required to support the plant. The building is located north of the Unit 3 Turbine Building. The Plant Services Building is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

14. The Radwaste Onsite Storage Facility provides temporary and long-term storage of radwaste. The Radwaste Onsite Storage Facility is located north of the Unit 2 and 3 powerplant structures and outside of the protected area boundary. The Radwaste Onsite Storage Facility is seismic Class II. The Radwaste Onsite Storage Facility is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function.

15. The Secondary Alarm Station Building provides housing for various security related equipment and personnel. The building is located east of the emergency cooling tower. The Secondary Alarm Station Building is classified as nonsafety-related and is separated from safety-related systems and structures or shown by analysis that its failure would not impact a safety-related function.

16. An onsite sewage treatment plant provides for treatment of normal sewage prior to release. The facility has the capacity to handle Units 2 and 3 and to handle the variable loading at the plant due to population fluctuations between outage and non-outage periods. The sewage treatment system is designed to provide an effluent that meets the regulations of the Commonwealth of Pennsylvania. The Sewage Treatment Structures are located southeast of the Diesel Generator Structure. The Sewage Treatment Structures are Seismic Class II and nonsafety-related. The Sewage Treatment Structures are classified as nonsafety-related and are separated from safety-related systems and structures such that failures would not impact a safety-related function.

17. The Site Management Building and attached shop provide office facilities and a small shop for management personnel and the other site work groups that are required to support the plant. The buildings are located on the south end of the parking lot, northeast of the Circulating Water Pump Structure, and are outside of the protected area boundary. The Site Management Building and attached shop are classified as nonsafety-related and are separated from safety-related systems and structures such that their failure would not impact a safety-related function.

18. Approximately 500 feet south of Units 2 and 3, and included in the exclusion area, is PBAPS Unit 1, a decommissioned high temperature, gas-cooled, 40 MWe nuclear power plant (Docket No. 50-171). Parts of Unit 1 and the entire adjacent Training Building are used for training. The Unit 1 and Training Building are classified as nonsafety-related and are separated from safety-related systems and structures such that failures would not impact a safety-related function.

19. The Warehouse Complex provides control and storage of materials and housing of personnel. The Warehouse Complex is located east of the Emergency Cooling Tower and Reservoir. The Warehouse Complex is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function or an analysis demonstrates that its failure would not impact a safety-related function of adjacent structures.

20. The Water Treatment Building provides support, shelter and protection for equipment and piping for treatment of raw water. The Water Treatment Building is located south of the Circulating Water Pump Structure. The Water Treatment Building is classified as nonsafety-related and is separated from safety-related systems and structures such that its failure would not impact a safety-related function or an analysis demonstrates that its failure would not impact a safety-related function of adjacent structures.

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL

2.3.1 REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

The following systems are addressed in this section:

- Reactor Pressure Vessel and Internals System (2.3.1.1)
- Reactor Pressure Vessel Instrumentation System (2.3.1.2)
- Reactor Recirculation System (2.3.1.3)
- Fuel Assemblies (2.3.1.4)

2.3.1.1 Reactor Pressure Vessel and Internals System

Description

The Reactor Pressure Vessel and Internals System includes the reactor pressure vessel, including nozzles, penetrations, and safe ends and welds to connecting piping, all components that are within the reactor pressure vessel, except for the fuel assemblies, and the reactor pressure vessel flange leak detection lines. The reactor pressure vessel is a vertical, cylindrical pressure vessel with hemispherical heads and is of welded construction. The cylindrical shell and bottom hemispherical head of the reactor pressure vessel are fabricated of low alloy steel plate. The shell is clad on the interior with a stainless steel overlay, and the bottom head with an inconel overlay. The major safety consideration for the reactor pressure vessel is the ability of the reactor pressure vessel to function as a radioactive material barrier. The reactor pressure vessel also provides a floodable core volume, contains the moderator, and provides support for the reactor internals.

The reactor internals are installed to properly distribute the flow of coolant delivered to the vessel, to locate and support the fuel assemblies, and to provide an inner volume containing the core that can be flooded following a break in the nuclear system process barrier external to the reactor pressure vessel.

The reactor pressure vessel and reactor internals are discussed in UFSAR Sections 3.3 and 4.2. The Reactor Pressure Vessel and Internals System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Pressure Vessel and Internals System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Reactor Pressure Vessel and Internals System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Pressure Vessel and Internals System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). The Reactor Pressure Vessel and Internals System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49).

Intended Functions

1. Provide reactor coolant pressure boundary. The reactor pressure vessel forms a barrier against the release of reactor coolant and radioactive material. 10 CFR 54.4(a)(1)

2. Maintain reactor core assembly geometry. The reactor pressure vessel provides support to the reactor internals. The reactor pressure vessel, along with the reactor internals, maintains a floodable volume within the reactor. 10 CFR 54.4(a)(1)

3. Introduce negative reactivity to achieve and maintain subcritical reactor condition. The control rods and CRD assemblies adjust the concentration of the neutron absorber in the core during normal operations and shutdown conditions. 10 CFR 54.4(a)(1)

4. Introduce emergency negative reactivity to make the reactor subcritical. When a Reactor Protection System scram signal is received, high pressure water is applied to the CRD assemblies to rapidly insert each control rod into the core. The core plate differential pressure and standby liquid control line provides a flowpath for injecting a neutron absorber into the reactor core when control rods are unavailable. 10 CFR 54.4(a)(1)

5. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. Neutron flux detectors within the reactor core initiate a Reactor Protection System scram signal to shutdown the reactor upon a high flux condition. 10 CFR 54.4(a)(1)

6. Provide emergency core cooling where the equipment provides coolant directly to the core. The core spray piping and spargers, internal to the reactor pressure vessel, distribute emergency core cooling flow within the shroud to the reactor core. 10 CFR 54.4(a)(1)

7. Provides structural support or restraint to SSCs in the scope of license renewal. The reactor pressure vessel support skirt and stabilizer brackets provide structural support for the reactor pressure vessel. 10 CFR 54.4(a)(1)

8. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Pressure Vessel and Internals System contains nonsafety-related, water-filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs. In addition, the nonsafety-related steam dryer could interact with safety-related components. 10 CFR 54.4(a)(2)

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The reactor pressure vessel provides the flow path and maintains the reactor coolant pressure boundary required for reactor safe shutdown. 10 CFR 54.4(a)(3)

10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The reactor pressure vessel provides the flow path and maintains the reactor coolant pressure boundary for standby liquid control injection. 10 CFR 54.4(a)(3)

11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The reactor pressure vessel provides the flow path and maintains the reactor coolant pressure boundary required for reactor safe shutdown. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

3.3.4
4.2.4
Table C.5.6
Appendix K

Second License Renewal Boundary Drawings

SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-352, Sheets 1, 2, 3, 4
SLR-PB-M-353, Sheets 1, 2, 3, 4
SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-376, Sheets 1, 2

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

Component Type	Intended Function
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary

Component Type	Intended Function
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N13 Flange Leak-Off) Reactor Vessel Nozzle	Direct Flow
	Pressure Boundary
(N14 Flange Leak-Off) Reactor Vessel Nozzle	Pressure Boundary
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Core Shroud and Core Plate: Access hole cover (Mechanical - Unit 3)	Direct Flow
	Mechanical Closure
Core Shroud and Core Plate: Access hole cover (Welded - Unit 2)	Direct Flow
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow
	Spray
Core Spray Sparger Nozzle Elbows	Direct Flow
Flow Device	Pressure Boundary
	Throttle
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, and Diffuser casting)	Direct Flow
Jet Pump Assemblies: Hold-down beam bolts	Mechanical Closure

Component Type	Intended Function
Jet Pump Assemblies: Jet pump sensing line	Direct Flow
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold-down beams, and Wedges	Direct Flow
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary
Reactor Vessel (Shell and Welds)	Pressure Boundary
Reactor Vessel (Upper Head)	Pressure Boundary
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure
	Pressure Boundary
Reactor Vessel External Attachments, Support Skirt, and Welds	Structural Support
Reactor Vessel Flange Leak Detection Line	Leakage Boundary
	Pressure Boundary
Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary
	Structural Integrity (Attached)
Reactor Vessel Internals Components (Jet Pump Auxiliary Wedges)	Structural Integrity (Attached)
Reactor Vessel Internals Components (Jet Pump Oversized Wedges)	Structural Integrity (Attached)
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Integrity (Attached)
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Integrity (Attached)
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution
	Throttle
Reactor Vessel Internals Components: Instrumentation	Structural Support to maintain core configuration and flow distribution
Reactor Vessel Internals Components: Steam Dryers	Structural Integrity (Attached)
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution

Component Type	Intended Function
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow
	Pressure Boundary
	Structural Support to maintain core configuration and flow distribution
Valve Body	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.1.2-1 Reactor Pressure Vessel and Internals System Summary of Aging Management Evaluation

2.3.1.2 Reactor Pressure Vessel Instrumentation System

Description

The Reactor Pressure Vessel Instrumentation monitors and transmits information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible in order to avoid (1) release of radioactive material such that the limits of 10 CFR 20 are exceeded, (2) nuclear system stress in excess of that allowed by applicable industry codes, and (3) the existence of any operating conditions not considered by plant safety analyses.

The Reactor Pressure Vessel Instrumentation System consists of components utilized for flow, water level, pressure, and temperature measurements required for the operation of the nuclear reactor under various normal, transient, shutdown, and accident conditions.

The Reactor Pressure Vessel Instrumentation System is designed to provide the operator with sufficient indication of the following:

- Reactor core flow rate during planned operations to avoid operating conditions not considered by plant safety analyses.
- Reactor pressure vessel water level during planned operations to determine that the core is adequately covered by the coolant inventory inside the reactor vessel to avoid the release of radioactive materials such that the limits of 10 CFR 20 are exceeded, and to avoid operating conditions not considered by plant safety analyses.
- Reactor pressure vessel pressure and temperature during planned operations to avoid operating conditions not considered by plant safety analyses.

The Reactor Pressure Vessel Instrumentation is described in UFSAR Section 7.8. The Reactor Pressure Vessel Instrumentation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Pressure Vessel Instrumentation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Reactor Pressure Vessel Instrumentation System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Pressure Vessel Instrumentation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide reactor coolant pressure boundary. The Reactor Pressure Vessel Instrumentation System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals for reactor trip or engineered safety functions. The Reactor Pressure Vessel Instrumentation System senses plant and process conditions and provides signals to initiate and to control engineered safety features. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. The Reactor Pressure Vessel Instrumentation System includes primary containment isolation valves. 10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Pressure Vessel Instrumentation System includes nonsafety-related fluid filled lines within the Reactor Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

5. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). Select components in the Reactor Pressure Vessel Instrumentation System provide process instrumentation that is credited in the event of a design basis fire. 10 CFR 54.4(a)(3)

6. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). Select components in the Reactor Pressure Vessel Instrumentation System are included in the Environmental Qualification Program. 10 CFR 54.4(a)(3)

7. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). Reactor vessel pressure (steam dome) and water level are initiation signals for alternate rod insertion. 10 CFR 54.4(a)(3)

8. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). Select components in the Reactor Pressure Vessel Instrumentation System provide process monitoring for the coping period and recovery following a station blackout. 10 CFR 54.4(a)(3)

UFSAR References

7.8

Second License Renewal Boundary Drawings

SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-352, Sheets 1, 2, 3, 4, 7, 8
SLR-PB-M-356, Sheets 1, 2
SLR-PB-M-357, Sheets 1, 2
SLR-PB-M-362, Sheets 1, 2

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

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

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

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System Summary of Aging Management Evaluation

2.3.1.3 Reactor Recirculation System

Description

The Reactor Recirculation System is a reactivity control system that serves to control reactor power levels by varying the coolant rate through the core over a limited range so that greater versatility is available in making power adjustments without the use of control rods.

The Reactor Recirculation System consists of two independent loops, external to the reactor pressure vessel, each with a motor driven centrifugal pump, suction and discharge valves, and piping. The Reactor Recirculation System is part of the reactor coolant pressure boundary, and functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas. The system piping and pump design pressures are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop.

The Reactor Recirculation System provides flow paths out of the reactor pressure vessel for Residual Heat Removal (RHR) and Reactor Water Cleanup Systems and into the reactor vessel for RHR shutdown cooling and low pressure coolant injection.

The coolant flow rate through the reactor core is varied by using adjustable speed drives and flow control instrumentation to change the speed of the centrifugal pumps to control the recirculation system drive flow rate.

A recirculation pump trip on reactor high pressure or reactor low water level has been provided to limit the consequences of a failure to scram during a transient.

The Reactor Recirculation System is discussed in detail in UFSAR Sections 4.3 and 7.9. The Reactor Recirculation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Recirculation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Reactor Recirculation System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Recirculation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide reactor coolant pressure boundary. The Reactor Recirculation System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building. 10 CFR 54.4(a)(1)

2. Provide primary containment boundary. The Reactor Recirculation System includes containment isolation valves. 10 CFR 54.4(a)(1)

3. Sense process conditions and generate signals for reactor trip or engineered safety features actuations. The Reactor Recirculation System includes instrumentation and process controls that provide input signals to the Reactor Protection System and ECCS systems. 10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Recirculation System includes nonsafety-related fluid filled lines within the Reactor Building and Containment Structure which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Reactor Recirculation System provides the flow path for reactor coolant make-up and decay heat removal, and maintains the reactor coolant pressure boundary in support of reactor safe shutdown. 10 CFR 54.4(a)(3)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Reactor Recirculation System includes safety-related components located within areas of the plant that may have harsh environments, and therefore have environmental qualifications. 10 CFR 54.4(a)(3)

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). Reactor Recirculation System components receive the recirculation pump trip signal from the Reactor Protection System and maintains reactor coolant pressure boundary. 10 CFR 54.4(a)(3)

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Reactor Recirculation System provides the flow path for reactor coolant make-up and decay heat removal, and maintains the reactor coolant pressure boundary in support of reactor safe shutdown. 10 CFR 54.4(a)(3)

UFSAR References

4.3
7.9

Second License Renewal Boundary Drawings

SLR-PB-M-316, Sheets 1, 3
SLR-PB-M-353, Sheets 1, 2, 3, 4
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-356, Sheets 1, 2
SLR-PB-M-361, Sheets 1, 2, 3, 4

Table 2.3.1-3 **Reactor Recirculation System**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Flow Device (Class 1)	Pressure Boundary
	Throttle
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary
Hoses	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (Lower Bearing Fill Metering Pump)	Leakage Boundary
Pump Casing (Recirc Pump)	Pressure Boundary
Tanks (Lower Bearing Oil Additional Tank)	Leakage Boundary
Tanks (Recirc Pump Motor Upper and Lower Bearing Oil Reservoir)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.1.2-3 Reactor Recirculation System
Summary of Aging Management Evaluation

2.3.1.4 Fuel Assemblies

Description

The Fuel Assemblies consist of nuclear fuel bundles that are high integrity assemblies of fissionable material that can be arranged in a critical array. Each nuclear fuel bundle must be capable of transferring the generated fission heat to the circulating coolant water while maintaining structural integrity and containing the fission products.

The nuclear fuel bundles are designed to assure that fuel damage limits will not be exceeded during either normal operation or anticipated operational occurrences. The Fuel Assemblies are utilized as the initial barrier for containment of fission products.

There are 764 nuclear fuel bundles in each reactor, with each nuclear fuel bundle consisting of a matrix of fuel rods.

The Fuel Assemblies are discussed in UFSAR Sections 3.2 and 3.6.

Reason for Scope Determination

The Fuel Assemblies meets 10 CFR 54.4(a)(1) because they are a safety-related system that is relied upon to remain functional during and following design basis events. The Fuel Assemblies are not in scope under 10 CFR 54.4(a)(2) because there are no nonsafety-related portions of the system. The Fuel Assemblies are not in scope under 10 CFR 54.4(a)(3) because they are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Maintain reactor core assembly geometry. The fuel assembly maintains geometry for any event to ensure core cooling, core reactivity control, and the integrity of the fuel cladding as a radioactive material boundary. 10 CFR 54.4 (a)(1)

UFSAR References

3.2
3.6

Second License Renewal Boundary Drawings

None.

Table 2.3.1-4 Fuel Assemblies
Components Subject to Aging Management Review

Component Type	Intended Function
Fuel Assembly (short-lived)	Not Applicable

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

Table 3.1.2-4 Fuel Assemblies
Summary of Aging Management Evaluation

2.3.2 ENGINEERED SAFETY FEATURES

The following systems are addressed in this section:

- Containment Atmosphere Control and Dilution System (2.3.2.1)
- Core Spray System (2.3.2.2)
- High Pressure Coolant Injection System (2.3.2.3)
- Primary Containment Isolation System (2.3.2.4)
- Reactor Core Isolation Cooling System (2.3.2.5)
- Residual Heat Removal System (2.3.2.6)
- Secondary Containment System (2.3.2.7)
- Standby Gas Treatment System (2.3.2.8)

2.3.2.1 Containment Atmosphere Control and Dilution System

Description

The Containment Atmosphere Control and Dilution System includes the containment atmosphere control (CAC) system and the containment atmospheric dilution (CAD) system. The CAC system is used to assure that the initial concentration of oxygen prior to a LOCA is maintained below the flammability limit of five percent within primary containment. This is done by maintaining the primary containment atmosphere inert with nitrogen and ensuring that no external sources of oxygen are introduced into containment as part of normal and post-accident operation.

During each startup, the primary containment is inerted with nitrogen until the atmosphere contains less than four percent oxygen. The CAC system is used during inerting of the primary containment to vent the air from containment and provide a supply of makeup nitrogen. The system consists of a liquid nitrogen storage tank, a water-bath vaporizer, ambient vaporizers, an electric heater, pressure-reducing valves and controller, instrumentation, valves, and piping.

The CAD system is a safety-related standby system used following a LOCA to maintain the oxygen concentration within the containment at less than five percent by volume. The CAD system nitrogen supply tank also supplies pressurized nitrogen to the Safety Grade Instrument Gas (SGIG) System to support operation of the CAC purge and vent valves, torus to secondary containment vacuum breakers, and the CAD vent valves following a DBA-LOCA.

The CAD system is composed of a common liquid nitrogen storage tank, redundant nitrogen electrical vaporizers, a pressure reducing valve, isolation valves, flow indication instrumentation, and flow control devices. Two piping systems are routed to each unit to provide redundant nitrogen supplies. The containment atmosphere is monitored for oxygen and hydrogen by combined CAD and CAC analyzers consisting of two redundant combustible gas analyzers subsystems. Each monitors torus and drywell oxygen and hydrogen for both the CAD and CAC systems.

A description of the Containment Atmosphere Control and Dilution System is provided in UFSAR Section 5.2. The Containment Atmosphere Control and Dilution System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Containment Atmosphere Control and Dilution System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Containment Atmosphere Control and Dilution System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Containment Atmosphere Control and Dilution System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and 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), and Station Blackout (10 CFR 50.63). The Containment Atmosphere Control and Dilution System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide primary containment boundary. The Containment Atmosphere Control and Dilution System includes piping and valves that are part of the primary containment boundary. The CAD nitrogen supply tank supplies pressurized nitrogen to the Safety Grade Instrument Gas System to support operation of the CAC purge and vent valves, torus to secondary containment vacuum breakers, and the CAD vent valves following a DBA-LOCA. 10 CFR 54.4(a)(1)

2. Control combustible gas mixtures within in the primary containment atmosphere. The Containment Atmosphere Control and Dilution System provides the capability to purge the containment with nitrogen and maintain containment atmosphere at less than five percent oxygen during normal operation. The Containment Atmosphere Control and Dilution System also includes instrumentation that monitors hydrogen and oxygen levels in containment during accident conditions. 10 CFR 54.4(a)(1)

3. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Containment Atmosphere Control and Dilution System includes instrumentation that monitors containment pressure and generates signals to the Reactor Protection System, Primary Containment Isolation System, and ECCS systems. 10 CFR 54.4(a)(1)

4. Provide emergency heat removal from primary containment and provide containment pressure control. The Containment Atmosphere Control and Dilution System includes flowpaths and equipment that provides a means to control containment pressure during normal power operation, transients, and design bases events. 10 CFR 54.4(a)(1)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Containment Atmosphere Control and Dilution System includes nonsafety-related piping components that have the potential for structural interaction with SSCs that perform a 10 CFR 54.4(a)(1) function. The Containment Atmosphere Control and Dilution System also includes nonsafety-related liquid-filled piping components that have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The containment pressure instrumentation and nitrogen storage tank within the Containment Atmosphere Control and Dilution System are credited for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The isolation of containment isolation valves and containment pressure instrumentation within the Containment Atmosphere Control and Dilution System are credited for the Station Blackout event. 10 CFR 54.4(a)(3)

UFSAR References

5.2

Second License Renewal Boundary Drawings

SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-367, Sheets 1, 2, 3
SLR-PB-M-372, Sheets 1, 2, 3, 4
SLR-PB-M-391, Sheets 1, 2
SLR-PB-M-397, Sheet 1

Table 2.3.2-1 Containment Atmosphere Control and Dilution System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Insulated Valve Body	Structural Integrity (Attached)
Insulated piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (Drywell/Torus CAC and CAD Sample Pump)	Pressure Boundary
Rupture Disks	Pressure Boundary
	Pressure Relief
Sensor Element	Pressure Boundary
Strainer (Element)	Filter
Tanks (CAD Liquid Nitrogen Storage Tank)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)

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

Table 3.2.2-1 Containment Atmosphere Control and Dilution System Summary of Aging Management Evaluation

2.3.2.2 Core Spray System

Description

The Core Spray System provides a redundant means for removal of decay heat from the core following a postulated LOCA. The system also provides a means for flooding the reactor vessel to remove decay heat from the core to support alternate shutdown cooling.

The system consists of two independent loops per unit, each with two 50 percent capacity motor driven pumps and associate piping, valves and instrumentation necessary to perform the system intended functions. The Core Spray System automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA. The system delivers cooling water at a sufficient flow rate to cool the core and prevent excessive fuel clad temperature. The low pressure coolant injection system initiates on the same signal as the Core Spray System and operates independently to fulfill the same objective as the Core Spray System. The system is maintained in a standby condition, powered by independent safeguard buses in the electrical distribution system.

The Core Spray 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 core spray pump room coolers are included in the scope of the Core Spray System.

The Core Spray System is described in detail in UFSAR Sections 5.3.2 and 6.4.3. The Core Spray System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Core Spray System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Core Spray System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Core Spray System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Core Spray System automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA. 10 CFR 54.4 (a)(1)

2. Provide reactor coolant pressure boundary. The Core Spray System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. The Core Spray System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)

4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Core Spray System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)

5. Maintain emergency temperature limits within areas containing safety-related components. The Core Spray System includes room coolers that maintain acceptable temperatures in the core spray pump rooms during Core Spray System operation. 10 CFR 54.4(a)(1)

6. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Core Spray System includes nonsafety-related water filled lines in the Reactor Building that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Core Spray System is credited for reactor vessel makeup for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Core Spray System includes primary containment isolation valves that are credited for Station Blackout coping and recovery. 10 CFR 54.4(a)(3)

10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Core Spray System includes fuses credited for ATWS. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

1.6.2.11
Table 5.2.2
5.3.2
6.4.3
6.5.3.3
7.4.3.3.2
7.4.3.4
7.19.1
Table A.10.1

<u>Second License Renewal Boundary Drawings</u>

SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-381, Sheet 1

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

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Flow Device (Class 1)	Pressure Boundary
	Throttle
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (Core Spray Pump Room Cooler) Fins	Heat Transfer
Heat Exchanger - (Core Spray Pump Room Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (Core Spray Pump Room Cooler) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (Core Spray Pump)	Pressure Boundary
Strainer (Element)	Filter
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

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

2.3.2.3 High Pressure Coolant Injection System

Description

The High Pressure Coolant Injection (HPCI) System provides cooling to the reactor, limiting fuel clad temperature in the event of a small break LOCA which does not result in rapid depressurization of the reactor pressure vessel. The HPCI System is designed to allow the plant to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI System continues to operate until the pressure in the reactor vessel is below the pressure at which Low Pressure Coolant Injection (LPCI) or Core Spray System operation maintains core cooling.

The HPCI System consists of a turbine-driven pump, piping, valves, and controls which provide for a complete and independent emergency core cooling system. The system includes a pressurized hydraulic oil control system that also provides lubrication to the pump and turbine. The safety-related water source for the HPCI System is from the suppression pool, with a back-up supply from the nonsafety-related condensate storage tank. Delivery of water to the reactor vessel occurs via the "A" feedwater line. Steam supply to the HPCI turbine is from the reactor vessel via the "B" main steam line. The system is equipped with a test line from the pump discharge that is shared with the Reactor Core Isolation Cooling (RCIC) System to facilitate functional testing, and a minimum flow bypass line which directs flow to the suppression pool for pump protection purposes during periods of low system flow. The exhaust steam from the turbine is discharged to the suppression pool.

The HPCI System is described in detail in UFSAR Section 6.4.1. The HPCI System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The High Pressure Coolant Injection System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The High Pressure Coolant Injection System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The High Pressure Coolant Injection System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the reactor core. The HPCI System is an emergency core cooling system that provides high pressure coolant to the reactor vessel for small reactor coolant system breaks. The HPCI System fulfills the objectives of the RCIC System in the event that the RCIC System is not available. 10 CFR 54.4(a)(1)

2. Provide reactor coolant pressure boundary. The HPCI System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. The HPCI System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)

4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The HPCI System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The HPCI System includes nonsafety-related liquid-filled SSCs in the Reactor Building and Turbine Building and Main Control Room Complex that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The HPCI System supports Appendix R Safe Shutdown. 10 CFR 54.4(a)(3)

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

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The HPCI System is credited for reactor vessel makeup for Station Blackout. 10 CFR 54.4(a)(3)

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The HPCI System is credited for reactor makeup if the feedwater system is not available. 10 CFR 54.4(a)(3)

UFSAR References

6.4.1
6.5.3.1
7.4.3.2

Second License Renewal Boundary Drawings

SLR-PB-M-303, Sheet 1
SLR-PB-M-306, Sheet 2
SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-365, Sheets 1, 2
SLR-PB-M-366, Sheets 1, 2, 3, 4
SLR-PB-M-381, Sheet 1
SLR-PB-M-397, Sheets 2, 3

Table 2.3.2-3 **High Pressure Coolant Injection System**
Components Subject to Aging Management Review

Component Type	Intended Function
Blower Housing (HPCI Gland Seal Condenser Vacuum Pump)	Leakage Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Drip Pan	Leakage Boundary
Flow Device	Pressure Boundary
	Throttle
Flow Device (Class 1)	Pressure Boundary
	Throttle
Gearbox (HPCI Pump Gearbox)	Pressure Boundary
Heat Exchanger - (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary
Heat Exchanger - (HPCI Lube Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (HPCI Lube Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (HPCI Lube Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (HPCI Lube Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (HPCI Pump Room Cooler) Shell Side Components	Structural Support
Heat Exchanger - (HPCI Pump Room Cooler) Tubes	Pressure Boundary
Hoses	Leakage Boundary
	Pressure Boundary
Piping elements	Leakage Boundary
	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (HPCI Aux Oil Pump)	Pressure Boundary

Component Type	Intended Function
Pump Casing (HPCI Booster Pump)	Pressure Boundary
Pump Casing (HPCI Gland Seal Condenser Condensate Pump)	Leakage Boundary
Pump Casing (HPCI Pump)	Pressure Boundary
Pump Casing (HPCI Turbine Driven Oil Pump)	Pressure Boundary
Strainer (Element)	Filter
Tanks (HPCI Turbine Lube Oil Reservoir)	Pressure Boundary
Turbine Casings (HPCI Turbine)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.2.2-3 High Pressure Coolant Injection System
Summary of Aging Management Evaluation

2.3.2.4 Primary Containment Isolation System

Description

The Primary Containment Isolation System is a plant protection system and includes the steam leak detection system. The system provides timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barrier. The primary containment and reactor vessel isolation control system initiates automatic isolation of appropriate lines that penetrate the primary containment whenever monitored variables exceed pre-selected operational limits.

The system initiates isolation of the reactor pressure vessel, isolation of piping which penetrate primary containment, and isolation of piping in selected balance of plant systems that provide potential paths for the release of radioactive materials.

The containment boundary valves and associated containment boundary piping from the following license renewal systems are aligned to the Primary Containment Isolation System: Process Sampling System, Primary Containment Leak Test System, Traversing In Core Probe System, Reactor Water Cleanup System, Torus Water Cleanup System, Instrument Nitrogen System, Backup Instrument Nitrogen to ADS System, Plant Equipment and Floor Drain System, Torus Water Storage and Transfer System, Reactor Building Closed Cooling Water System, Service Air Systems, and Chilled Water System.

The Primary Containment Isolation System is discussed in additional detail in UFSAR Sections 5.1, 5.2, 7.3, and Appendix M. The Primary Containment Isolation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Primary Containment Isolation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Primary Containment Isolation System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Primary Containment Isolation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide reactor coolant pressure boundary. The Primary Containment Isolation System includes piping and valves that are part of the reactor coolant pressure boundary.
10 CFR 54.4(a)(1)

2. Provide primary containment boundary. The Primary Containment Isolation System includes piping and valves that are part of the primary containment boundary.
10 CFR 54.4(a)(1)

3. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Primary Containment Isolation System includes instrumentation that provides signals for reactor pressure vessel and primary containment isolation, various system isolations, and equipment interlocks. 10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Primary Containment Isolation System includes nonsafety-related water filled lines in the Reactor Building and Containment Structure that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Primary Containment Isolation System is credited for reactor pressure vessel and primary containment isolation, various system isolations, and equipment interlocks for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Primary Containment Isolation System is credited for reactor pressure vessel and primary containment isolation, various system isolations, and equipment interlocks for Station Blackout. 10 CFR 54.4(a)(3)

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Primary Containment Isolation System is credited for reactor pressure vessel and primary containment isolation, various system isolations, and equipment interlocks. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

5.1
5.2
7.3
Appendix M.3

<u>Second License Renewal Boundary Drawings</u>

SLR-PB-M-311, Sheets 1, 7
SLR-PB-M-316, Sheets 1, 3
SLR-PB-M-320, Sheets 21, 41
SLR-PB-M-327, Sheets 2, 4
SLR-PB-M-332, Sheets 1, 2
SLR-PB-M-333, Sheets 1, 2
SLR-PB-M-351, Sheets 2, 4
SLR-PB-M-354, Sheets 1, 2

SLR-PB-M-359, Sheets 1, 2
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2
SLR-PB-M-367, Sheets 1, 2
SLR-PB-M-368, Sheet 1
SLR-PB-M-369, Sheet 1
SLR-PB-M-373, Sheet 1
SLR-PB-M-376, Sheets 1, 2

Table 2.3.2-4 Primary Containment Isolation System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device (Class 1)	Pressure Boundary
	Throttle
Insulated Valve Body	Pressure Boundary
Insulated piping, piping components	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Valve Body (Class 1)	Pressure Boundary

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

Table 3.2.2-4 Primary Containment Isolation System
Summary of Aging Management Evaluation

2.3.2.5 Reactor Core Isolation Cooling System

Description

The Reactor Core Isolation Cooling (RCIC) System is a high pressure reactor coolant makeup system which supports safe shutdown of the reactor whenever the reactor is isolated from its normal heat sink. The RCIC System provides sufficient makeup capacity to accommodate decay heat boil-off during a normal reactor shutdown. The system facilitates reactor vessel depressurization until the shutdown cooling mode of the Residual Heat Removal (RHR) System can be placed in operation.

The RCIC System consists of a turbine-driven pump, piping, valves, and a pressurized hydraulic oil control system. The primary water source is from the condensate storage tank, with a backup supply of water available from the suppression pool. Delivery of water to the reactor vessel is via the "B" feedwater line. Steam supply to the RCIC turbine is from the reactor vessel via the "C" main steam line. The system includes a test line from the pump discharge shared with the High Pressure Coolant Injection (HPCI) System to facilitate functional testing and a minimum flow bypass line which directs flow to the suppression pool for pump protection purposes during periods of low system flow. The exhaust steam from the turbine is directed to the suppression pool.

The RCIC System is described in detail in UFSAR Section 4.7. The RCIC System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Core Isolation Cooling System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Reactor Core Isolation Cooling System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Core Isolation Cooling System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Remove residual heat from the reactor coolant system. The RCIC system provides high pressure coolant flow to the reactor vessel. 10 CFR 54.4 (a)(1)

2. Provide reactor coolant pressure boundary. The RCIC System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. The RCIC System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)

4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The RCIC System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The RCIC System includes nonsafety-related liquid-filled SSCs in the Reactor Building and Turbine Building and Main Control Room Complex that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The RCIC System is credited for reactor vessel makeup for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The RCIC System is credited for reactor vessel makeup for Station Blackout. 10 CFR 54.4(a)(3)

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The RCIC System is credited for reactor makeup if the feedwater system is not available. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

4.7

<u>Second License Renewal Boundary Drawings</u>

SLR-PB-M-303, Sheet 1
SLR-PB-M-306, Sheet 2
SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-359, Sheets 1, 2,
SLR-PB-M-360, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2
SLR-PB-M-381, Sheet 1

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

Component Type	Intended Function
Blower Housing (RCIC Barometric Condenser Vacuum Pump)	Leakage Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Flow Device (Class 1)	Pressure Boundary
	Throttle
Gearbox (RCIC Turbine Bearing Cavity)	Pressure Boundary
Heat Exchanger - (RCIC Lube Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (RCIC Lube Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (RCIC Lube Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (RCIC Lube Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (RCIC Pump Room Cooler) Shell Side Components	Structural Support
Heat Exchanger - (RCIC Pump Room Cooler) Tubes	Pressure Boundary
Hoses	Leakage Boundary
	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (RCIC Barometric Condenser Condensate Pump)	Leakage Boundary
Pump Casing (RCIC Pump)	Pressure Boundary
Strainer (Element)	Filter
Tanks (RCIC Barometric Condenser and Vacuum Tank)	Leakage Boundary
Turbine Casings (RCIC Turbine)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.2.2-5	Reactor Core Isolation Cooling System Summary of Aging Management Evaluation

2.3.2.6 Residual Heat Removal System

Description

The Residual Heat Removal (RHR) System is an emergency core cooling system and heat removal system. The RHR System restores and maintains the coolant inventory in the reactor vessel such that the core is adequately cooled after a LOCA. The system also provides containment cooling by condensing steam resulting from the blowdown due to a design basis accident.

The RHR System consists of two independent loops. Each loop consists of two heat exchangers, two parallel RHR pumps, plus the associated piping, valves, and instrumentation. The loops are located in different areas of the Reactor Building to minimize the possibility of a single physical event causing the loss of the entire system.

The RHR System is designed for three modes of operation: shutdown cooling, containment cooling, and low-pressure injection. Each mode of operation is defined as a subsystem of the RHR System, with each subsystem contributing toward satisfaction of all objectives and design bases of the system.

The shutdown cooling subsystem is placed in operation during a normal shutdown and cooldown. The subsystem uses one or more RHR heat exchangers to remove reactor core decay heat and sensible heat from the reactor core to achieve and maintain the reactor in a cold shutdown condition.

The containment cooling subsystem provides a means for cooling the containment when operating in either the suppression pool cooling or containment spray modes. The suppression pool cooling mode provides a means to remove the reactor core decay heat and sensible heat discharged to the suppression pool in the event of a design basis accident or event. The containment cooling subsystem also provides the ability to reduce containment pressure by using the spray headers in the drywell and above the suppression pool.

The low pressure coolant injection (LPCI) subsystem operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperature. The LPCI subsystem operates in conjunction with the high pressure coolant injection system, the automatic depressurization system, and the core spray system to achieve this goal. The LPCI subsystem is designed to reflood the reactor vessel to at least two-thirds core height and maintain this level. After the core has been flooded to this height, the capacity of one RHR pump is more than sufficient to maintain the level.

The RHR pump room coolers are included as part of the RHR System.

The RHR system is described in detail in UFSAR Section 4.8. The RHR System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Residual Heat Removal System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Residual Heat Removal System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Residual Heat Removal System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide reactor coolant pressure boundary. The RHR System provides Class 1 piping and valves which are part or the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

2. Remove residual heat from the reactor coolant system. The RHR System removes decay and sensible heat from the reactor primary system. 10 CFR 54.4(a)(1)

3. Provide emergency core cooling where the equipment provides coolant directly to the core. The RHR System provides water from the suppression pool to be injected directly into the core region of the reactor vessel following a LOCA. 10 CFR 54.4(a)(1)

4. Provide primary containment boundary. The RHR System provides safety-related primary containment isolation capability on containment spray discharge, suppression pool suction, test return, and sample lines penetrating the primary containment. 10 CFR 54.4(a)(1)

5. Provide emergency heat removal from primary containment and provide containment pressure control. The RHR System supports maintaining the suppression pool temperature below required limits following a reactor blowdown. The RHR System also provides spray headers in the drywell and suppression pool vapor spaces to maintain internal pressure below design limits. 10 CFR 54.4(a)(1)

6. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The RHR System provides for associated actuation and system protection logic for engineered safety features operation. 10 CFR 54.4(a)(1)

7. Maintain emergency temperature limits within areas containing safety-related components. The RHR System provides room coolers for the RHR pump rooms to maintain emergency temperature limits within areas containing safety-related components. 10 CFR 54.4(a)(1)

8. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. The RHR System provides additional cooling capacity for spent fuel pool cooling. 10 CFR 54.4(a)(1)

9. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The RHR System contains nonsafety-related fluid filled lines within the Reactor Building which have the potential for spatial interaction with safety-related SSCs. The RHR System includes nonsafety-related piping that is in scope to provide a seismic anchor credited for structural support of safety-related piping. 10 CFR 54.4(a)(2)

10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The RHR System is credited for reactor makeup and heat removal for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The RHR System has components credited in the Environmental Qualification program. 10 CFR 54.4(a)(3)

12. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The primary containment heat removal and pressure control functions of the RHR System are credited for Anticipated Transient Without Scram. 10 CFR 54.4(a)(3)

13. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The primary containment isolation and decay heat removal functions of the RHR System are credited for Station Blackout coping. 10 CFR 54.4(a)(3)

UFSAR References

4.8
6.4.4
Table 7.3.1
10.5
14.10.5.1

Second License Renewal Boundary Drawings

SLR-PB-M-315, Sheets 1, 2, 3, 4
SLR-PB-M-326, Sheets 2, 6
SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-370, Sheet 1
SLR-PB-M-372, Sheets 1, 2
SLR-PB-M-374, Sheets 1, 2
SLR-PB-M-381, Sheet 1

Table 2.3.2-6 **<u>Residual Heat Removal System</u>**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (RHR Pump Room Cooler) Fins	Heat Transfer
Heat Exchanger - (RHR Pump Room Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (RHR Pump Room Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (RHR Pump)	Pressure Boundary
Spray Nozzles	Spray
Strainer (Element)	Filter
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.2.2-6 Residual Heat Removal System
Summary of Aging Management Evaluation

2.3.2.7 Secondary Containment System

Description

The Reactor Building, in conjunction with the reactor building heating and ventilating system and the Standby Gas Treatment System (up to and including the second outboard isolation valve) constitutes the secondary containment. This includes penetrations of the Reactor Building. The penetrations for piping, ventilation ducts, electrical cables, and instrument leads are sealed. The ventilation ducts are provided with valves for automatic closure when reactor building isolation is required. Refer to SLRA Section 2.4 for a description of the Reactor Building.

The Reactor Building completely encloses the primary containment, and auxiliary systems of the nuclear steam supply system, and houses the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The secondary containment serves as the containment during reactor refueling when the primary containment is open, and as an additional fission product barrier when the primary containment is functional.

The Secondary Containment license renewal system includes the following portion of the reactor building HVAC system: the valves which isolate secondary containment, along with the associated ductwork and controls. The Secondary Containment System interfaces with the Standby Gas Treatment System, which is evaluated separately. The reactor building is evaluated with the Reactor Building license renewal structure, and the penetrations and doors are evaluated with Hazard Barriers and Elastomers license renewal structural commodity.

The Secondary Containment is described in UFSAR Sections 5.1 and 5.3. The Secondary Containment System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Secondary Containment System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Secondary Containment System is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Secondary Containment System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide secondary containment boundary. The function of the Secondary Containment System is to provide treatment and controlled release of radioactive materials that may leak from or may be released outside of the primary containment. 10 CFR 54.4(a)(1)

UFSAR References

5.1
5.3

Second License Renewal Boundary Drawings

SLR-PB-M-391, Sheets 1, 2

Table 2.3.2-7 Secondary Containment System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve Body	Pressure Boundary

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

Table 3.2.2-7 Secondary Containment System
Summary of Aging Management Evaluation

2.3.2.8 Standby Gas Treatment System

Description

The Standby Gas Treatment System (SGTS) is an engineered safety feature system for limiting the ground level release from the Reactor Building. The system also provides for an elevated release of primary and secondary containment air via the main stack.

The system is common to both Units 2 and 3 and is located in a shielded room in the radwaste building between the reactor buildings.

The SGTS consists of two parallel filter trains connected to three full capacity exhaust fans. Each filter train is made up of the following components: moisture separator, electric resistance heater, pre-filter, high-efficiency filter, charcoal filter, and another high efficiency filter downstream of the charcoal filter. Each fan is capable of exhausting the rated flow through either filter train and up through the main stack.

The system interfaces with the normal reactor building ventilation system exhaust piping and ductwork. Two exhaust lines from each Reactor Building connect to the common filter train inlet plenum. One line is connected to the reactor building refueling floor ventilation exhaust duct. The second line is connected to the reactor building air spaces below the refuel floor, and also to the suppression pool and drywell.

A fire protection system is provided at each of the charcoal filter trays, and is evaluated with the Fire Protection System.

The SGTS is described in detail in UFSAR Section 5.3.3. The SGTS boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Standby Gas Treatment System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Standby Gas Treatment System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Standby Gas Treatment System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) and Station Blackout (10 CFR 50.63). The Standby Gas Treatment System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Control and treat radioactive materials released to the secondary containment. The SGTS maintains a negative pressure within Reactor Building, and filters the exhaust air to reduce halogen and particulate concentrations in gases prior to their elevated release point.
10 CFR 54.4(a)(1)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The SGTS includes nonsafety-related instrument air purge lines that are relied upon to preserve the structural support intended function of the system. 10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout. (10 CFR 50.63) The SGTS is relied upon to be operable for coping, shutdown, and recovery following a station blackout event. 10 CFR 54.4(a)(3)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The SGTS contains pressure differential instrumentation that is environmentally qualified. 10 CFR 54.4(a)(3)

UFSAR References

5.3.3

Second License Renewal Boundary Drawings

SLR-PB-M-310, Sheet 2
SLR-PB-M-367, Sheets 1, 2
SLR-PB-M-391, Sheets 1, 2
SLR-PB-M-397, Sheets 1, 2, 3

Table 2.3.2-8 Standby Gas Treatment System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Filter
	Pressure Boundary
Flexible Connection	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Valve Body	Pressure Boundary

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

Table 3.2.2-8 Standby Gas Treatment System
Summary of Aging Management Evaluation

2.3.3 AUXILIARY SYSTEMS

The following systems are addressed in this section:

- Auxiliary Steam System (2.3.3.1)
- Backup Instrument Nitrogen to ADS System (2.3.3.2)
- Battery and Emergency Switchgear Ventilation System (2.3.3.3)
- Chilled Water System (2.3.3.4)
- Condensate Transfer System (2.3.3.5)
- Control Rod Drive System (2.3.3.6)
- Control Room Ventilation System (2.3.3.7)
- Cranes and Hoists System (2.3.3.8)
- Diesel Generator Building Ventilation System (2.3.3.9)
- Domestic Water System (2.3.3.10)
- Emergency Cooling Water System (2.3.3.11)
- Emergency Diesel Generator System (2.3.3.12)
- Emergency Service Water System (2.3.3.13)
- Fire Protection System (2.3.3.14)
- Fuel Handling System (2.3.3.15)
- Fuel Pool Cooling and Cleanup System (2.3.3.16)
- High Pressure Service Water System (2.3.3.17)
- Offgas and Recombiner System (2.3.3.18)
- Plant Equipment and Floor Drain System (2.3.3.19)
- Post Accident Sampling System (2.3.3.20)
- Process Sampling System (2.3.3.21)
- Pump Structure Ventilation System (2.3.3.22)
- Radiation Monitoring System (2.3.3.23)
- Radwaste System (2.3.3.24)
- Reactor Building Closed Cooling Water System (2.3.3.25)
- Reactor Water Cleanup System (2.3.3.26)
- Refueling Water Storage and Transfer System (2.3.3.27)
- Safety Grade Instrument Gas System (2.3.3.28)
- Service Water System (2.3.3.29)
- Standby Liquid Control System (2.3.3.30)
- Suppression Pool Temperature Monitoring System (2.3.3.31)
- Torus Water Cleanup System (2.3.3.32)
- Torus Water Storage and Transfer System (2.3.3.33)
- Traveling Water Screen System (2.3.3.34)
- Turbine Building Closed Cooling Water System (2.3.3.35)
- Water Treatment System (2.3.3.36)

2.3.3.1 Auxiliary Steam System

Description

The Auxiliary Steam System is a normally operating system designed to provide steam necessary to accommodate the varying steam demands during all seasons and modes of operation. The system provides a source of low pressure non-contaminated steam for various startup functions and plant heating services.

The Auxiliary Steam System is relied upon to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure-retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes steam and liquid-filled portions of the system located within the reactor building, turbine building, diesel generator building, radwaste building, reactor auxiliary bay, nitrogen storage building, and circulating water pump structure.

The Auxiliary Steam System is described in UFSAR Section 10.23. The Auxiliary Steam System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Auxiliary Steam System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Auxiliary Steam System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Auxiliary Steam System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Auxiliary Steam System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Auxiliary Steam System contains nonsafety-related, steam and water-filled lines in the Reactor Building, Turbine Building and Main Control Room Complex, Diesel Generator Building, Radwaste Building and Reactor Auxiliary Bay, Nitrogen Storage Building, and Circulating Water Pump Structure which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Auxiliary Steam System includes manual valves credited for Fire Safe Shutdown that are closed to preclude heating of outdoor air being used by the Control Room Ventilation System to cool the Control Room. 10 CFR 54.4(a)(3)

UFSAR References

10.23

Second License Renewal Boundary Drawings

SLR-PB-M-314, Sheet 8
SLR-PB-M-324, Sheet 3
SLR-PB-M-325, Sheets 1, 3, 4, 5, 6, 8
SLR-PB-M-359, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2
SLR-PB-M-367, Sheet 3
SLR-PB-M-381, Sheet 1
SLR-PB-M-384, Sheets 1, 2, 3
SLR-PB-M-398, Sheets 1, 4
SLR-PB-M-399, Sheets 1, 2

Table 2.3.3-1 Auxiliary Steam System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger - (Condensate Return Unit Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Condensate Return Unit Cooler) Tubes	Leakage Boundary
Heat Exchanger - (HVAC Heater Coils) Tube Side Components	Leakage Boundary
Heat Exchanger - (HVAC Heater Coils) Tubes	Leakage Boundary
Heat Exchanger - (Heating System Condensate Coolers) Shell Side Components	Leakage Boundary
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary
Heat Exchanger - (Unit Heaters) Tubes	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Condensate Pumps)	Leakage Boundary
Tanks (Condensate Return Tanks)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-1 Auxiliary Steam System
Summary of Aging Management Evaluation

2.3.3.2 Backup Instrument Nitrogen to ADS System

Description

The Backup Instrument Nitrogen to ADS System consists of a split ring header with seismic Category I piping and valves, three nitrogen bottles located in the Reactor Building, and an external nitrogen connection located outside the Reactor Building at ground level. The split ring header supplies five automatic depressurization system (ADS) valves, three from one section of the header, and two from the other section.

The Backup Instrument Nitrogen to ADS System provides a safety-related pneumatic supply of nitrogen to the ADS valves in the event that the instrument nitrogen system is unavailable or inoperable. The source of the safety-related pneumatic pressure is a series of nitrogen bottles located within the Reactor Building with a connection provided outside the Reactor Building for the installation of additional bottles, as required.

The Backup Instrument Nitrogen to ADS System supports ADS in its emergency core cooling and residual heat removal capacity by providing a safety-related pneumatic supply capable of sustaining ADS operation for 100 days post-accident.

The Backup Instrument Nitrogen to ADS System is described in UFSAR Sections 4.4 and 10.17. The Backup Instrument Nitrogen to ADS System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Backup Instrument Nitrogen to ADS System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Backup Instrument Nitrogen to ADS System is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Backup Instrument Nitrogen to ADS System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and 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), and Station Blackout (10 CFR 50.63). The Backup Instrument Nitrogen to ADS System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide motive power to safety-related components. The Backup Instrument Nitrogen to ADS System provides a safety-related, long-term supply of nitrogen for motive power to the five ADS valves. 10 CFR 54.4(a)(1)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Backup Instrument Nitrogen to ADS System is credited for providing a long-term supply of nitrogen for motive power to the five ADS valves. 10 CFR 54.4(a)(3)

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

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Backup Instrument Nitrogen to ADS System is credited for providing a long-term supply of nitrogen for motive power to the five ADS valves. 10 CFR 54.4(a)(3)

UFSAR References

4.4
10.17

Second License Renewal Boundary Drawings

SLR-PB-M-333, Sheets 1, 2
SLR-PB-M-351, Sheets 1, 2, 3, 4

Table 2.3.3-2 Backup Instrument Nitrogen to ADS System
Components Subject to Aging Management Review

Component Type	Intended Function
Accumulator (Instrument N2 Accumulator)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Hoses	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve Body	Pressure Boundary

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

Table 3.3.2-2 Backup Instrument Nitrogen to ADS System
Summary of Aging Management Evaluation

2.3.3.3 Battery and Emergency Switchgear Ventilation System

Description

The Battery and Emergency Switchgear Ventilation System consists of a common air supply system and separate exhaust systems. Outdoor air is filtered, conditioned by heating coils when required, and discharged by one of the two supply fans to the emergency switchgear and battery rooms of Units 2 and 3. One of the two emergency switchgear room return air fans exhaust air to atmosphere at the radwaste building roof or back to the suction of the supply fan as controlled by an air-operated damper. One of the two battery room exhaust fans discharges exhaust air from the battery rooms to atmosphere at the radwaste building roof. Loss of duct pressure automatically starts standby fans and sounds an alarm in the main control room. The Battery and Emergency Switchgear Ventilation System is provided with a safety-related nitrogen backup supply for damper operation.

The Battery and Emergency Switchgear Ventilation System is normally in operation and continues to operate during accident conditions including the loss of offsite power. All system controls are from a local panel. Redundant fans are provided for reliable system operation.

The Battery and Emergency Switchgear Ventilation System is described in detail in UFSAR Section 10.14. The Battery and Emergency Switchgear Ventilation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Battery and Emergency Switchgear Ventilation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Battery and Emergency Switchgear Ventilation System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Battery and Emergency Switchgear Ventilation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Battery and Emergency Switchgear Ventilation System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Maintain emergency temperature limits within areas containing safety-related components. The Battery and Emergency Switchgear Ventilation System provides ventilation to the safety-related equipment in the emergency switchgear and battery rooms. 10 CFR 54.4(a)(1)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Battery and Emergency Switchgear Ventilation System contains nonsafety-related components relied upon to preserve the structural support intended function of the system. 10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Battery and Emergency Switchgear Ventilation System is relied upon to be operable during and following a fire event for explosion protection. 10 CFR 54.4(a)(3)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout. (10 CFR 50.63). The Battery and Emergency Switchgear Ventilation System is relied upon to provide ventilation after establishing alternate AC power and for recovery following a station blackout event. 10 CFR 54.4(a)(3)

UFSAR References

10.14
7.19

Second License Renewal Boundary Drawings

SLR-PB-M-389, Sheet 1
SLR-PB-M-399, Sheets 1, 4

Table 2.3.3-3 Battery and Emergency Switchgear Ventilation System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Valve Body	Pressure Boundary

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

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System Summary of Aging Management Evaluation

2.3.3.4 Chilled Water System

Description

The intended function of the Chilled Water System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure-retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid-filled portions of the system located within the containment, reactor building and radwaste building. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support license renewal intended functions, and is in scope only for potential spatial interaction. The containment isolation valves and associated support and control equipment associated with the Chilled Water System are evaluated with the Primary Containment Isolation System.

The Chilled Water System is described in UFSAR Section 10.11. The Chilled Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Chilled Water System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Chilled Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Chilled Water System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Chilled Water System contains nonsafety-related, water-filled lines in the Containment Structure, Reactor Building, and Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.11

Second License Renewal Boundary Drawings

SLR-PB-M-327, Sheets 1, 2, 3, 4
SLR-PB-M-328, Sheet 1
SLR-PB-M-353, Sheets 1, 2, 3, 4
SLR-PB-M-368, Sheet 1
SLR-PB-M-369, Sheet 1
SLR-PB-M-384, Sheets 2, 3
SLR-PB-M-398, Sheet 1
SLR-PB-M-399, Sheet 2

Table 2.3.3-4 Chilled Water System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Drip Pan	Leakage Boundary
Heat Exchanger - (Cable Spreading Room Cooling Coils) Tube Side Components	Leakage Boundary
Heat Exchanger - (Cable Spreading Room Cooling Coils) Tubes	Leakage Boundary
Heat Exchanger - (Control Room A/C Supply Cooling Coils) Tube Side Components	Leakage Boundary
Heat Exchanger - (Control Room A/C Supply Cooling Coils) Tubes	Leakage Boundary
Heat Exchanger - (Control Room North Office Cooling Coil) Tube Side Components	Leakage Boundary
Heat Exchanger - (Control Room North Office Cooling Coil) Tubes	Leakage Boundary
Heat Exchanger - (Drywell Area Cooling Coils) Tube Side Components	Leakage Boundary
Heat Exchanger - (Drywell Area Cooling Coils) Tubes	Leakage Boundary
Heat Exchanger - (Drywell Equipment Sump Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Health Physics and Chem Labs Supply Cooling Coils) Tube Side Components	Leakage Boundary
Heat Exchanger - (Health Physics and Chem Labs Supply Cooling Coils) Tubes	Leakage Boundary
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tube Sheet	Leakage Boundary
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tubes	Leakage Boundary
Hoses	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Insulated piping, piping components	Leakage Boundary
Piping, piping components	Leakage Boundary

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

Table 3.3.2-4 Chilled Water System
Summary of Aging Management Evaluation

2.3.3.5 Condensate Transfer System

Description

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

The Condensate Transfer System is described in UFSAR Sections 4.8.5, 6.5.3, 11.7 and 11.8. The Condensate Transfer System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Condensate Transfer System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Condensate Transfer System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Condensate Transfer System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Condensate Transfer System contains nonsafety-related, water-filled lines in the Reactor Building, Turbine Building and Main Control Room Complex, and Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

4.8.5
6.5.3
11.7
11.8

Second License Renewal Boundary Drawings

SLR-PB-M-307, Sheets 3, 6
SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-310, Sheets 1, 3
SLR-PB-M-355, Sheets 1, 3
SLR-PB-M-361, Sheets 2, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-364, Sheets 1, 2
SLR-PB-M-370, Sheets 1, 2
SLR-PB-M-371, Sheets 1, 2, 3, 4, 5

Table 2.3.3-5 Condensate Transfer System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-5 Condensate Transfer System
Summary of Aging Management Evaluation

2.3.3.6 Control Rod Drive System

Description

The Control Rod Drive (CRD) System is a reactivity control system that utilizes pressurized demineralized water to rapidly insert control rods to shutdown the reactor upon receipt of a scram signal from the Reactor Protection System. The CRD System also provides for manual control of core reactivity and power generation by incrementally positioning neutron-absorbing control rods in response to signals from the Reactor Manual Control System. The CRD System includes the alternate rod insertion (ARI) system, which provides an alternate means of venting the scram air header and inserting control rods that is independent of the Reactor Protection System. The ARI function serves to reduce the probability of an ATWS event and may be initiated automatically or manually.

The CRD System also provides a source of cool, clean, high pressure water to the Reactor Recirculation System pump seals, the Reactor Water Cleanup System pump motors, and to the condensing chambers associated with reactor level instrumentation to maintain a continuous purge of the reference legs.

The CRD System is described in detail in UFSAR Section 3.4. The CRD System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Control Rod Drive System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Control Rod Drive System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Control Rod Drive System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide reactor coolant pressure boundary. Piping components from the control rod drive mechanisms through components at the hydraulic control units, including the scram inlet and outlet valves, directional control valves and piping back to the check valves from the cooling water and charging water headers are part of the reactor coolant pressure boundary.
10 CFR 54.4(a)(1)

2. Introduce negative reactivity to achieve or maintain subcritical reactor condition. The hydraulic control units provide the motive force to the control rod drive mechanisms to rapidly insert control rods during a scram event to prevent or limit fuel damage following abnormal transients and design bases accidents. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. Various valves on the hydraulic control units provide containment isolation function from the reactor coolant pressure boundary at the control rod drive mechanisms. The automatic vent and drain valves on the scram discharge volume provide automatic containment isolation function during a scram event.
10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Control Rod Drive System includes nonsafety-related water-filled, pressure-retaining piping and equipment within the Reactor Buildings that have the potential for spatial interaction with safety-related equipment. 10 CFR 54.4(a)(2)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Fire Protection (10 CFR 50.48). The Control Rod Drive System includes equipment that is credited by Fire Safe Shutdown analysis to shutdown the reactor via the scram function. 10 CFR 54.4(a)(3)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Environmental Qualification (10 CFR 50.49). The Control Rod Drive System includes equipment that is required to be environmentally qualified. 10 CFR 54.4(a)(3)

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Control Rod Drive System includes the alternate rod insertion system that provides an alternate means of venting the scram air header and inserting control rods that is independent of the Reactor Protection System. 10 CFR 54.4(a)(3)

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Station Blackout (10 CFR 50.63). The station blackout analysis credits the Control Rod Drive System with successfully inserting all control rods upon receipt of scram initiation signals from the Reactor Protection System.
10 CFR 54.4(a)(3)

UFSAR References

3.4

Second License Renewal Boundary Drawings

SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-356, Sheets 1, 2
SLR-PB-M-357, Sheets 1, 2

Table 2.3.3-6 **Control Rod Drive System**
Components Subject to Aging Management Review

Component Type	Intended Function
Accumulator (HCU)	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Rupture Disks	Pressure Boundary
	Pressure Relief
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.3.2-6 Control Rod Drive System
Summary of Aging Management Evaluation

2.3.3.7 Control Room Ventilation System

Description

The Control Room Ventilation System is a safety-related system that is common to Units 2 and 3. The system consists of several subsystems: control room fresh air supply, control room emergency ventilation filter, control room air conditioning ventilation supply, and the control room return air system. The system ensures the habitability of the control room even under the design basis events. The fresh air portion of the system is operable during the loss of offsite power. The fresh air intake is filtered when control room emergency ventilation is initiated to prevent iodine and particulate contamination of the control room air.

The system consists of normal and emergency ventilation supply fans, air conditioning supply and return fans, filters, heating coils and cooling coils, refrigerant water chillers, chilled water pumps, dampers, ductwork, instrumentation, and controls.

The control room fresh air supply system consists of two 100 percent capacity, redundant supply fans, roll filter, and preheat coil. The system is supplied with outside air from the outside air intake plenum.

The control room emergency ventilation filter system is a safety-related system which consists of two 100 percent capacity filter units and redundant supply fans. Each filter unit consists of a charcoal filter and two banks of HEPA filters upstream and downstream of the charcoal filter.

The Control Room Ventilation System is described in detail in UFSAR Section 10.13. The Control Room Ventilation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Control Room Ventilation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Control Room Ventilation System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Control Room Ventilation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Control Room Ventilation System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide centralized area for control and monitoring of nuclear safety-related equipment. The Control Room Ventilation System maintains environmental conditions and ensures the safety and comfort of operating personnel in the control room. The system also provides a filtered fresh air supply during adverse plant conditions. 10 CFR 54.4(a)(1)

2. Maintain emergency temperature limits within areas containing safety-related components. The Control Room Ventilation System maintains environmental conditions to ensure that the operability of safety-related equipment in the control room. 10 CFR 54.4(a)(1)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Control Room Ventilation System includes nonsafety-related instrument air purge lines that are relied upon to preserve the structural support intended function of the system. 10 CFR 54.4(a)(2)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Control Room Ventilation System is relied upon to be operable during and following a fire event for explosion protection. 10 CFR 54.4(a)(3)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Control Room Ventilation System is relied upon to provide ventilation after establishing alternate AC power and for recovery following a station blackout event. 10 CFR 54.4(a)(3)

UFSAR References

10.13
7.19

Second License Renewal Boundary Drawings

SLR-PB-M-384, Sheets 1, 2, 3

Table 2.3.3-7 Control Room Ventilation System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Valve Body	Pressure Boundary

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

Table 3.3.2-7 Control Room Ventilation System
Summary of Aging Management Evaluation

2.3.3.8 Cranes and Hoists System

Description

The reactor building cranes are safety-related and designed to Seismic Class 1 criteria. All other in scope cranes and hoists are nonsafety-related. Cranes, hoists, and monorail beams that handle loads above or near safety-related systems, structures, and components are in scope for license renewal. Postulated failure of these cranes, hoists, and monorail beams could impact a safety-related function. The following components within the Cranes and Hoists System are in scope for license renewal:

- Reactor Building Cranes
- Turbine Building Cranes
- Emergency Diesel Generator Cranes
- Circulating Water Pump Structure Crane
- Recirculation Pump Motor-Generator Set Monorails
- Emergency Cooling Tower Jib Crane and Hoist
- Service Pole Caddy Platform Overhead Hoist
- Equipment Access Airlock Monorails & Hoists
- Unit 2A Southwest Torus Hatch Hoist
- Personnel Airlock Hoists
- Unit 2 Pre-coat Material Handling Hoist
- Fuel Channel Handling Hoists
- CRD Cask Hoists
- CRD Jib Cranes
- Recirculation Pump Motor Hoists
- Drywell Elevation 170' Monorail Hoists (MSRV Removal Hoists)
- Turbine Building West Side Vertical Restraint Rigging Hoist
- Turbine Building East Side Vertical Restraint Rigging Hoist
- 1-Ton Crane Over CRD Storage Area
- Jib Crane/Hoist for RPV Cavity Work Platform
- Radwaste Building Demin Hoist
- Dewatering Building Coffing Hoist
- U3 1 Ton Crane Over Repair Area
- 3B Recirc Pump Motor Redundant Rigging Hoist

Reason for Scope Determination

The Cranes and Hoists System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Cranes and Hoists System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Cranes and Hoists System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR

50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provides physical support, shelter and protection for safety-related systems, structures, and components. The reactor building crane is safety-related, seismically qualified, and is used to transport heavy loads over irradiated fuel and above or near safety-related components. 10 CFR 54.4(a)(1)

2. Provides a safe means for handling safety-related components and loads above or near safety-related components. The Cranes and Hoists System components within the scope of license renewal handle equipment above or near safety-related components or spent fuel. 10 CFR 54.4(a)(2)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The nonsafety-related in scope components within the Cranes and Hoists System components provide a safe means for handling loads above or near safety-related components. 10 CFR 54.4(a)(2)

UFSAR References

10.4.10
10.4.11

Second License Renewal Boundary Drawings

None

Table 2.3.3-8 Cranes and Hoists System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Cranes: Rails, Bridges, Structural Members, Structural Components	Structural Support

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

Table 3.3.2-8 Cranes and Hoists System Summary of Aging Management Evaluation

2.3.3.9 Diesel Generator Building Ventilation System

Description

The Diesel Generator Building Ventilation System provides heating, cooling and ventilation for personnel comfort, for the diesel generators and associated equipment, and for the ESW booster pumps. The system provides ventilation and cooling to the emergency diesel generator rooms during normal plant operation and following design basis events. It supplies heating as required during normal operating conditions. The system also provides ventilation, cooling, and heating as required to the Cardox and Emergency Service Water (ESW) System booster pump room during normal plant operating conditions.

Each emergency diesel generator room is provided with ventilation air supply fans and an exhaust relief damper. The ventilation systems are supplied with power from the diesels during the loss of offsite power. Combustion air for the diesel engine is taken from the room. The diesel engine combustion air components are evaluated with the Emergency Diesel Generator System.

The Diesel Generator Building Ventilation System is described in detail in UFSAR Section 10.14. The Diesel Generator Building Ventilation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Diesel Generator Building Ventilation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Diesel Generator Building Ventilation System is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Diesel Generator Building Ventilation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Diesel Generator Building Ventilation System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Maintain emergency temperature limits within areas containing safety-related components. The Diesel Generator Building Ventilation System provides ventilation to the safety-related equipment in the emergency diesel generator rooms and ESW booster pump room. 10 CFR 54.4(a)(1)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Diesel Generator Building Ventilation System is relied upon to be operable during and following fire safe shutdown events. 10 CFR 54.4(a)(3)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout. (10 CFR 50.63). The Diesel Generator Building Ventilation System is relied upon to be operable following a station blackout event. 10 CFR 54.4(a)(3)

UFSAR References

10.14

Second License Renewal Boundary Drawings

SLR-PB-M-392, Sheet 1

Table 2.3.3-9 Diesel Generator Building Ventilation System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve Body	Pressure Boundary

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

Table 3.3.2-9 Diesel Generator Building Ventilation System Summary of Aging Management Evaluation

2.3.3.10 Domestic Water System

Description

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

The Domestic Water System is described in UFSAR Section 10.18. The Domestic Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Domestic Water System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Domestic Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Domestic Water System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Portions of the Domestic Water System in the Reactor Buildings, Radwaste Building and Reactor Auxiliary Bay, Administration Building and Shop, and Turbine Building and Main Control Room Complex have a leakage boundary intended function due to potential spatial interaction with safety-related equipment. 10 CFR 54.4(a)(2)

UFSAR References

10.18

Second License Renewal Boundary Drawings

SLR-PB-M-317, Sheet 1

Table 2.3.3-10 Domestic Water System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Insulated Valve Body	Leakage Boundary
Insulated piping, piping components	Leakage Boundary

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

Table 3.3.2-10 Domestic Water System
Summary of Aging Management Evaluation

2.3.3.11 Emergency Cooling Water System

Description

The Emergency Cooling Water (ECW) System is designed to remove, via the Emergency Service Water (ESW) System and High Pressure Service Water (HPSW) System, the sensible and decay heat from the reactor primary and auxiliary systems so that the reactor can be shutdown in the event of the unavailability of the normal heat sink. The ECW System consists of one ECW pump, two ESW booster pumps, three fans in the Emergency Cooling Tower and Reservoir, an induced draft three-cell cooling tower with integral storage reservoir and associated discharge and distribution piping.

When the normal heat sink is lost, or when flooding occurs, sluice gates in the Circulating Water Pump Structure are closed. Water is provided through two gravity fed lines from the Emergency Cooling Tower and Reservoir into the Circulating Water Pump Structure. The ECW pump in conjunction with the ESW pumps, ESW booster pumps, and HPSW pumps, supply cooling water to heat exchangers required to bring Units 2 and 3 to safe shutdown. Return water from the HPSW System flows to the Emergency Cooling Tower and Reservoir. Return water from the ESW System flows through one of the two ESW booster pumps and is pumped into the Emergency Cooling Tower and Reservoir.

The emergency cooling tower structure and fill are evaluated with the Emergency Cooling Tower and Reservoir license renewal structure. The sluice gates are evaluated with the Circulating Water Pump Structure.

The Emergency Cooling Water System is discussed in detail in UFSAR Section 10.24. The Emergency Cooling Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Emergency Cooling Water System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Emergency Cooling Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Emergency Cooling Water System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Emergency Cooling Water System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63)

Intended Functions

1. Provides heat removal from safety-related heat exchangers. The ECW System provides cooling water to transfer heat from the ESW System and the HPSW System during the mitigation of a flood or loss of the Conowingo Pond and loss of offsite power.
10 CFR 54.4(a)(1)

2. Provides heat removal from safety-related heat exchangers. The ECW System is available to provide a reliable back-up source of cooling water to the ESW System during normal plant operations in the unlikely failure of an ESW Pump and loss of offsite power.
10 CFR 54.4(a)(1)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The ECW System includes nonsafety-related water filled lines in the Emergency Cooling Tower and Reservoir and Circulation Water Pump Structure that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The ECW System is credited for equipment isolation for a Fire Safe Shutdown. 10 CFR 54.4(a)(3)

UFSAR References

10.24
14.10.5.1
14.10.5.3

Second License Renewal Boundary Drawings

SLR-PB-M-330, Sheet 1

Table 2.3.3-11 Emergency Cooling Water System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Pump Casing (ECW Pump)	Pressure Boundary
Pump Casing (ESW Booster Pump)	Pressure Boundary
Pump Casing (Emergency Cooling Tower Sump Pump)	Leakage Boundary
Spray Nozzles	Spray
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-11 Emergency Cooling Water System
Summary of Aging Management Evaluation

2.3.3.12 Emergency Diesel Generator System

Description

The Emergency Diesel Generator System includes four emergency diesel generators (EDGs) that supply independent standby AC power to Units 2 and 3. Each EDG set consists of a diesel engine, a generator, and auxiliary systems (starting air, fuel oil, jacket cooling, engine exhaust and combustion air, and lubricating oil). Each EDG is connected to one 4kV Class 1E emergency bus per unit. The 4kV emergency switchgear bus distributes AC power to engineered safeguard and selected non-safeguard systems. Power provided to engineered safeguard loads is divided into four safeguard channels, "A" through "D", for each unit so that the failure of one EDG or one 4kV emergency bus will not prevent a safe shutdown of either unit.

Each EDG is automatically started on loss of offsite power, low reactor water level, or high drywell pressure signals. The EDGs are connected to the 4kV emergency buses upon a loss of offsite power after generator voltage and frequency are established.

The EDGs are housed in a seismic Class I, watertight Diesel Generator Building. Each EDG is enclosed in its own concrete cell, with an independent ventilation system and is isolated from the other EDGs. The building location is separate from the power block.

The Emergency Diesel Generator System is described in UFSAR Section 8.5. The Emergency Diesel Generator System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Emergency Diesel Generator System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Emergency Diesel Generator System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Emergency Diesel Generator System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). The Emergency Diesel Generator System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49).

Intended Functions

1. Provide motive power to safety-related components. The Emergency Diesel Generator System is required to power safety-related equipment in the event normal offsite power sources are not available. 10 CFR 54.4(a)(1)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Emergency Diesel Generator System includes nonsafety-related fluid filled lines in the diesel rooms that have the potential for spatial interactions with safety-related SSCs. The starting air system includes nonsafety-related piping that is in scope to provide a seismic anchor credited for structural support of safety-related piping.
10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Emergency Diesel Generator System includes fuses that are credited for mitigation of the ATWS event. 10 CFR 54.4(a)(3)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Emergency Diesel Generator System provides power to safe shutdown equipment in the event of a loss of offsite power coincident with the postulated fire for several analyzed Fire Safe Shutdown methods. 10 CFR 54.4(a)(3)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). The Emergency Diesel Generator System provides power to the 4 kV buses during Station Blackout event. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

1.6
5.2
8.5

<u>Second License Renewal Boundary Drawings</u>

SLR-PB-M-377, Sheets 1, 2, 3, 4, 5
SLR-PB-M-392, Sheet 1

Table 2.3.3-12 Emergency Diesel Generator System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Compressor Housing (D/G Starting Air)	Structural Integrity (Attached)
Electric Heaters (D/G Jacket Coolant and D/G Lube Oil Standby Heater Housings)	Pressure Boundary
Expansion Joint	Pressure Boundary
Flame Arrestor	Pressure Boundary
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger - (D/G Air Coolant Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (D/G Air Coolant Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Air Coolant Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Hoses	Leakage Boundary
	Pressure Boundary
Piping elements	Leakage Boundary
	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (D/G Fuel Oil Auxiliary)	Pressure Boundary
Pump Casing (D/G Fuel Oil Transfer)	Pressure Boundary
Pump Casing (D/G Jacket Coolant Standby Circ)	Pressure Boundary
Pump Casing (D/G Lube Oil Pre-Lube)	Pressure Boundary
Pump Casing (D/G Lube Oil Standby Circ)	Pressure Boundary
Pump Casing (Flex Fuel Oil Transfer)	Leakage Boundary
Strainer (Element)	Filter

Component Type	Intended Function
Tanks (D/G Coolant Expansion Tank)	Pressure Boundary
Tanks (D/G Dirty Fuel Oil Drain)	Leakage Boundary
Tanks (D/G Fuel Oil Day Tank)	Pressure Boundary
Tanks (D/G Fuel Oil Storage Tank)	Pressure Boundary
Tanks (D/G Lube Oil Storage)	Pressure Boundary
Tanks (D/G Starting Air Reservoir)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)

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

Table 3.3.2-12 Emergency Diesel Generator System
Summary of Aging Management Evaluation

2.3.3.13 Emergency Service Water System

Description

The Emergency Service Water (ESW) System provides a reliable supply of cooling water to the Emergency Diesel Generator System heat exchangers, Core Spray System pump room coolers, High Pressure Coolant Injection (HPCI) System pump room coolers, Reactor Core Isolation Cooling (RCIC) System pump room coolers, Residual Heat Removal (RHR) System pump room coolers, Core Spray System pump motor oil coolers, and other selected equipment during a loss of offsite power or during a loss of normal station service water.

The system consists of two 100 percent capacity ESW System pumps, heat exchangers, associated discharge and distribution piping, piping components, valves and instrumentation and controls. The two ESW System pumps take suction from individual pump bays within the Circulating Water Pump Structure. A return header in each unit returns the water to the discharge pond or the Emergency Cooling Water (ECW) System. During normal operations, all system loads with the exception of the Emergency Diesel Generator System heat exchangers are supplied with cooling water from the Service Water System. The ESW System provides the cooling water whenever the pumps are operating and the ESW System pressure is greater than Service Water System pressure or the Service Water System is manually isolated from the ESW System. In the event of extreme high or low Conowingo Pond level, the ESW System can be shifted to closed cycle operation through the use of the ECW System.

The ESW System is described in UFSAR Section 10.9. The ESW System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Emergency Service Water System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Emergency Service Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Emergency Service Water System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and 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), and Station Blackout (10 CFR 50.63). The Emergency Service Water System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The ESW System provides cooling water flow to the Emergency Diesel Generator System heat exchangers, Core Spray System pump motor oil coolers, RHR System pump seal coolers, during a loss of offsite power or during a loss of normal station service water due to flood conditions or the loss of the Conowingo Pond. 10 CFR 54.4(a)(1)

2. Maintain emergency temperature limits within areas containing safety-related components. The ESW System provides cooling water flow to the RHR System pump room coolers and the Core Spray System pump room coolers during a loss of offsite power or during a loss of normal station service water due to flood conditions or the loss of the Conowingo Pond. 10 CFR 54.4(a)(1)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The ESW System includes nonsafety-related water filled lines in the Reactor Building, Administration Building and Shop, and Circulating Water Pump Structure that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The ESW System is credited for equipment and ventilation cooling for a Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The ESW System is credited for equipment and ventilation cooling during coping and recovery. 10 CFR 54.4(a)(3)

<u>UFSAR References</u>

10.9
14.10.5.1
14.10.5.3

<u>Second License Renewal Boundary Drawings</u>

SLR-PB-M-314, Sheets 4, 8
SLR-PB-M-315, Sheets 1, 2, 4, 5
SLR-PB-M-330, Sheet 1
SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-377, Sheets 2, 3
SLR-PB-M-381, Sheet 1

Table 2.3.3-13 <u>Emergency Service Water System</u>
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flexible Connection	Leakage Boundary
	Pressure Boundary
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (Core Spray Pump Room Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (Core Spray Pump Room Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (D/G Air Coolant Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Air Coolant Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (D/G Air Coolant Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (D/G Jacket Coolant Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (D/G Lube Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (HPCI Pump Room Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (HPCI Pump Room Cooler) Tubes	Pressure Boundary
Heat Exchanger - (RCIC Pump Room Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (RCIC Pump Room Cooler) Tubes	Pressure Boundary

Component Type	Intended Function
Heat Exchanger - (RHR Pump Room Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger - (RHR Pump Room Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary
Insulated Valve Body	Pressure Boundary
Insulated piping, piping components	Pressure Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components with Internal Coatings	Pressure Boundary
Pump Casing (ESW Chemical Injection Pumps)	Leakage Boundary
Pump Casing (ESW Pumps)	Pressure Boundary
Tanks (Chemical Tank)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-13 Emergency Service Water System
Summary of Aging Management Evaluation

2.3.3.14 Fire Protection System

Description

The term "fire protection system" refers to the integrated complex of components and equipment provided for detection and suppression of fires. In addition to this system, the "fire protection program" includes the concepts of design and layout implemented to prevent or mitigate fires, administrative controls and procedures, and personnel training. The fire protection program uses a defense-in-depth approach aimed at preventing fires, minimizing the effect of any fires that occur, providing appropriate fire detection and suppression equipment, and training personnel in fire prevention and firefighting.

The Fire Protection System detects the presence of smoke or excessive heat in designated plant areas, provides local alarms, control room annunciation horn and printed record, and suppression system activation. The Fire Protection System includes various types of water, foam, and carbon dioxide suppression systems. Additionally, the Fire Protection System includes active and passive features such as walls, floors, fire doors, fire dampers, penetration seals, fire wraps, combustible free zones, and water curtains which retard fires from spreading from one area of the plant to another. Heat and smoke detection is accomplished by the appropriate detectors installed in areas where fire potential exists and in all areas containing safety-related equipment except where a specific exemption was granted by the NRC. The circuits of these installations go directly to local system panels. The local panels contain detector circuits for supervisory and alarm functions and trouble circuits for remote indication.

Circuits for annunciation are physically separated from those circuits that actuate the fire suppression systems. Detection of fire by any smoke or heat detector will activate an audible control room alarm with visual annunciation and printed record of event.

The source of water for the PBAPS fire protection system is the Circulating Water Pump Structure. This source allows continuous operation of either pump as long as required. The fire pumps take suction from independent, isolatable intake wells. Check valves are installed at the pump discharges to prevent water from one well from being pumped into the other well.

The low pressure carbon dioxide systems provide fire suppression to areas where an inert electrically nonconductive suppression medium is required or desirable. A fixed foam system is provided for the protection of the auxiliary boiler fuel oil storage tank.

There are two vertical fire pumps, each rated for 2,500 gpm at 125 psig total head. The lead pump is electric-motor-driven, and the 100 percent capacity backup pump is diesel-engine-driven. The pumps and their controllers are UL-listed.

The system is capable of supplying water at the required pressure for the largest sprinkler flow plus 500 gpm.

The Fire Protection system is described in detail in PBAPS Fire Protection Program (FPP). The Fire Protection System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Fire Protection System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Fire Protection System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Fire Protection System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). The Fire Protection System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62) or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Fire Protection System includes nonsafety-related water filled lines in the Circulating Water Pump Structure and other areas of the plant that contain safety-related equipment that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Fire Protection (10 CFR 50.48). The Fire Protection System provides the capability to control postulated fires in plant areas to maintain safe shutdown ability. 10 CFR 54.4(a)(3)

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

UFSAR References

1.6.5.6
10.12
FPP

Second License Renewal Boundary Drawings

SLR-PB-M-318, Sheets 1, 2, 3, 4, 6, 10
SLR-PB-M-323, Sheet 1
SLR-PB-M-379, Sheet 1
SLR-PB-M-397, Sheet 1

Table 2.3.3-14 <u>Fire Protection System</u>
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Concrete elements: Curbs	Fire Barrier
Fire Barriers	Fire Barrier
Fire Barriers (Damper Assembly)	Fire Barrier
Fire Barriers (For Steel Components)	Fire Barrier
Fire Barriers- concrete walls, ceilings, floors	Fire Barrier
Fire Barriers- doors	Fire Barrier
Fire Barriers- masonry walls	Fire Barrier
Fire Barriers- penetration seals	Fire Barrier
Fire Hydrant	Pressure Boundary
Flame Arrestor	Pressure Boundary
Flexible Connection	Pressure Boundary
Flow Device	Pressure Boundary
	Throttle
Gearbox	Pressure Boundary
Hose Stations	Structural Support
Odorizer	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components with Internal Coatings	Pressure Boundary
Pump Casing (Diesel Driven Fire Pump Fuel Oil Transfer Pump)	Pressure Boundary
Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary
Pump Casing (Motor Driven Fire Pump)	Pressure Boundary
Spray Nozzles	Spray
Sprinklers	Pressure Boundary
	Spray
Strainer (Element)	Filter
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary
Tanks (Diesel Fire Pump Fuel Oil Storage Tank)	Pressure Boundary
Tanks (Emergency D/G BLDG Cardox)	Pressure Boundary
Tanks (Foam Tank)	Pressure Boundary
Tanks (Retard Chamber)	Pressure Boundary
Tanks (Turbine Building Cardox Unit)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body with Internal Coatings	Pressure Boundary

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

Table 3.3.2-14 Fire Protection System
Summary of Aging Management Evaluation

2.3.3.15 Fuel Handling System

Description

The Fuel Handling System includes the safety-related refueling platforms and fuel preparation machines that are used to safely handle new and irradiated fuel, reactor components, and equipment used for refueling activities above or near safety-related components or irradiated fuel. The Unit 2 and Unit 3 refueling floors are physically separated with each unit having its own Fuel Handling System. The Fuel Handling System includes refueling interlocks consisting of instrumentation and controls that ensure safe refueling operations and prevent inadvertent criticality during refueling operations.

The refueling platforms consist of a platform on a bridge structure that spans the fuel storage pool and the reactor well. The platform travels on rails that extend the length of the fuel storage pool and the reactor well. The refueling platform includes the following hoists for handling fuel, equipment, or reactor components:

- Main Fuel Grapple Hoist and Mast
- Frame Mounted Hoist
- Auxiliary (Monorail) Hoist

Two fuel preparation machines located in each fuel storage pool are used to install and remove channels from fuel assemblies.

Reason for Scope Determination

The Fuel Handling System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Fuel Handling System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Fuel Handling System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. The refueling platforms and fuel preparation machines are safety-related, seismically qualified, and handle equipment and fuel over irradiated fuel and above or near safety-related components. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Fuel Handling System includes interlocks and other automatic controls that restrict the movement of refueling equipment, fuel, and control rods to prevent inadvertent criticality during refueling operations. 10 CFR 54.4(a)(1)

3. Provides a safe means for handling safety-related components and loads above or near safety-related components. The Fuel Handling System components within the scope of license renewal handle equipment and fuel above or near safety-related components or irradiated fuel. 10 CFR 54.4(a)(2)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The nonsafety-related Fuel Handling System components within the scope of license renewal provide a safe means for handling equipment and fuel above or near safety-related components or irradiated fuel. 10 CFR 54.4(a)(2)

UFSAR References

7.6
10.4

Second License Renewal Boundary Drawings

None.

Table 2.3.3-15 Fuel Handling System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Crane/hoist (Auxiliary Work Platform and Jib Crane)	Structural Support
Crane/hoist (Fuel Prep Machine)	Structural Support
Crane/hoist (Reactor Service Platform)	Structural Support
Crane/hoist (Refueling Platform)	Structural Support
Crane/hoist (Refueling Platform-Mast)	Structural Support
Crane/hoist (Service Pole Caddy Platform)	Structural Support

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

Table 3.3.2-15 Fuel Handling System
Summary of Aging Management Evaluation

2.3.3.16 Fuel Pool Cooling and Cleanup System

Description

The Fuel Pool Cooling and Cleanup System provides control of fuel pool water temperature and maintains fuel pool water clarity, purity, and level. The Fuel Pool Cooling and Cleanup System cools the fuel storage pool by transferring the decay heat from spent fuel assemblies to the service water system via heat exchangers. Water purity and clarity in the fuel storage pool, are maintained by filtering and demineralizing the pool water. During refueling outages, the reactor well, and steam dryer and separator pit can be interconnected with the fuel pool.

The Fuel Pool Cooling and Cleanup System consists of three fuel pool cooling pumps, three heat exchangers, two skimmer surge tanks, and associated piping, valves, and instrumentation. The three fuel pool cooling pumps are connected in parallel, as are the three heat exchangers. Each unit has a dedicated filter demineralizer and there is one filter demineralizer that can be used by either Unit 2 or 3. Interconnections with the Residual Heat Removal (RHR) System provide backup heat removal function for the fuel pools if the Fuel Pool Cooling and Cleanup System is unavailable.

The fuel pools, pumps and heat exchangers are located in the Reactor Buildings. The filter demineralizers and associated piping and components are located in the radwaste building. Interconnecting piping between the fuel pools, the refueling water storage tank, and the condensate storage tanks are located in the turbine buildings.

The Fuel Pool Cooling and Cleanup System is described in detail in UFSAR Section 10.5. The Fuel Pool Cooling and Cleanup System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Fuel Pool Cooling and Cleanup System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Fuel Pool Cooling and Cleanup System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Fuel Pool Cooling and Cleanup System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. The Fuel Pool Cooling and Cleanup System includes safety-related components that interface with the RHR System in support of the RHR System intended function to provide adequate cooling for spent fuel. 10 CFR 54.4(a)(1).

2. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. The Fuel Pool Cooling and Cleanup System includes nonsafety-related piping components between the fuel pools and the RHR System in support of the RHR System intended function to provide adequate cooling for spent fuel. 10 CFR 54.4(a)(2)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Fuel Pool Cooling and Cleanup System includes nonsafety-related liquid-filled SSCs in the Reactor Buildings, Turbine Building and Main Control Room Complex, and Radwaste Building and Reactor Auxiliary Bay that have the potential for spatial interactions (spray or leakage) with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.5

Second License Renewal Boundary Drawings

SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-364, Sheets 1, 2
SLR-PB-M-370, Sheet 1
SLR-PB-M-371, Sheet 3

Table 2.3.3-16 Fuel Pool Cooling and Cleanup System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger - (Fuel Pool Cooling Heat Exchanger) Shell Side Components	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Pump Casing (Fuel Pool Cooling Pumps)	Leakage Boundary
Pump Casing (Fuel Pool F/D Holding Pump)	Leakage Boundary
Pump Casing (Waste Precoat Pump)	Leakage Boundary
Strainer (Element)	Filter
Tanks (Fuel Pool Filter Demineralizer)	Leakage Boundary
Tanks (Fuel Pool Skimmer Surge Tank)	Pressure Boundary
Tanks (Waste Precoat Tank)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System
Summary of Aging Management Evaluation

2.3.3.17 High Pressure Service Water System

Description

The High Pressure Service Water (HPSW) System provides cooling water for the Residual Heat Removal (RHR) System heat exchangers under normal, hot standby, refueling and post-accident conditions. The system provides core decay heat removal capability during shutdown periods, and containment cooling during normal operations and during post accident conditions. The HPSW pumps are located in the Seismic Class I portion of the Circulating Water Pump Structure.

The system consists of four pumps per unit and the necessary piping, valves and controls to provide cooling water from either the Conowingo Pond or the Emergency Cooling Tower and Reservoir via the HPSW pump bay. The pumps deliver cooling water at a pressure greater than RHR System pressure. This ensures radioactive leakage from the RHR System to the environs is inhibited. Under abnormal operating conditions, RHR System pressure could exceed HPSW System pressure. Radioactivity due to leakage into the HPSW System is monitored upstream and downstream of the RHR heat exchangers to detect activity in potential release paths. The HPSW System discharges through one pipe for each unit to the discharge pond.

Radiation monitoring equipment is evaluated with the Radiation Monitoring System.

The HPSW system is described in detail in UFSAR Section 10.7. The HPSW System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The High Pressure Service Water System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The High Pressure Service Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The High Pressure Service Water System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The HPSW System provides cooling water flow to transfer heat from the RHR Heat Exchangers for post-accident shutdowns. 10 CFR 54.4(a)(1)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The HPSW System includes nonsafety-related water filled lines in the Reactor Building and Circulating Water Pump Structure that have the potential for spatial interaction (spray or leakage) or structural interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). The HPSW System is credited for reactor decay heat removal for a Fire Safe Shutdown.
10 CFR 54.4(a)(3)

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

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). The HPSW System is credited for reactor decay heat removal during coping and recovery.
10 CFR 54.4(a)(3)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The HPSW System contains two electrical motor starters which are credited for an ATWS. 10 CFR 54.4(a)(3)

UFSAR References

10.7
FPP Section 5.2
14.10.5.1
14.10.5.3

Second License Renewal Boundary Drawings

SLR-PB-M-315, Sheets 1, 3
SLR-PB-M-330, Sheet 1
SLR-PB-M-361, Sheets 1, 2, 3, 4

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

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Shell Side Components	Pressure Boundary
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tube Side Components	Pressure Boundary
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer
	Pressure Boundary
Insulated Valve Body	Pressure Boundary
Insulated piping, piping components	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Pump Casing (High Pressure Service Water Pumps)	Pressure Boundary
Strainer (Element)	Filter
Valve Body	Leakage Boundary
	Pressure Boundary

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

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

2.3.3.18 Offgas and Recombiner System

Description

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

The Offgas and Recombiner System is described in UFSAR Sections 9.4, and 11.4. The Offgas and Recombiner System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Offgas and Recombiner System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Offgas and Recombiner System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Offgas and Recombiner System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Offgas and Recombiner System contains nonsafety-related, water-filled lines in the Turbine Building and Main Control Room Complex which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

9.4
11.4

Second License Renewal Boundary Drawings

SLR-PB-M-310, Sheets 2, 4
SLR-PB-M-331, Sheets 1, 3, 5, 7

Table 2.3.3-18 Offgas and Recombiner System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Tanks (Offgas Drain Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-18 Offgas and Recombiner System
Summary of Aging Management Evaluation

2.3.3.19 Plant Equipment and Floor Drain System

Description

The Plant Equipment and Floor Drain System is a normally operating system designed to collect various liquids generated in the operation of the plant. The license renewal Plant Equipment and Floor Drain System consists of the following plant systems: the floor drain collection system, the equipment drain collection system, portions of the sewage collection system, portions of the circulating water system floor drains and sump, the diesel generator sump system, and roof drain collection piping for various plant structures

The Plant Equipment and Floor Drain System is relied upon to maintain leakage boundary integrity to preclude system interactions in the Containment Structures, Reactor Buildings, Diesel Generator Building, Emergency Cooling Tower and Reservoir, and areas of the turbine buildings, radwaste building, and Circulating Water Pump Structure that house safety-related SSCs.

The Plant Equipment and Floor Drain System is described in UFSAR Sections 9.2, 9.3, 9.4, 10.18, and 10.19. The Plant Equipment and Floor Drain System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Plant Equipment and Floor Drain System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related and relied upon to remain functional during and following design basis events. The Plant Equipment and Floor Drain System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Plant Equipment and Floor Drain System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Plant Equipment and Floor Drain System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. The Plant Equipment and Floor Drain System floor drains located in the Circulating Water Pump Structure HPSW and ESW pump compartments and the Circulating Water Pump Structure sump pumps are in scope because they perform an (a)(2) credited function to mitigate internal flooding of the HPSW and ESW pumps compartments. 10 CFR 54.4(a)(2)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Plant Equipment and Floor Drain System includes nonsafety-related water-filled piping and components located in areas that contain safety-related equipment have the potential for spatial interaction with safety-related SSCs.
10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform intended functions that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). Portions of the system's floor drain piping located in areas with safety-related equipment and fixed fire liquid suppression systems are sized to remove expected sprinkler system and hose station flow. Additionally, portions of the system's floor drain piping located within specific dikes which contain with main turbine and reactor feed pump turbine lube oil have been isolated from the remainder of the Plant Equipment and Floor Drain System.
10 CFR 54.4(a)(3)

UFSAR References

9.2
9.3
9.4
10.18
10.19

Second License Renewal Boundary Drawings

SLR-PB-M-307, Sheets 2, 3, 5, 6
SLR-PB-M-308, Sheets 1, 3
SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-310, Sheet 2
SLR-PB-M-314, Sheets 1, 2, 3, 4, 5, 6, 7, 8
SLR-PB-M-315, Sheets 1, 3, 4, 5, 6, 7
SLR-PB-M-316, Sheets 1, 2, 3, 4
SLR-PB-M-318, Sheets 1, 3
SLR-PB-M-319, Sheet 4
SLR-PB-M-320, Sheets 6, 26
SLR-PB-M-326, Sheets 1, 2, 3, 6, 7, 12, 13
SLR-PB-M-327, Sheets 2, 4
SLR-PB-M-330, Sheet 1
SLR-PB-M-331, Sheets 1, 3, 5, 7
SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-353, Sheets 1, 2, 3, 4
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-355, Sheets 1, 2, 3, 4
SLR-PB-M-356, Sheets 1, 2
SLR-PB-M-357, Sheets 1, 2
SLR-PB-M-358, Sheets 1, 2
SLR-PB-M-359, Sheets 1, 2
SLR-PB-M-360, Sheets 1, 2
SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-364, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2
SLR-PB-M-366, Sheets 1, 2, 3, 4
SLR-PB-M-367, Sheets 1, 2
SLR-PB-M-368, Sheet 1

SLR-PB-M-369, Sheet 1
SLR-PB-M-370, Sheets 1, 2, 3
SLR-PB-M-371, Sheets 1, 2, 3, 4, 7
SLR-PB-M-372, Sheets 1, 2
SLR-PB-M-377, Sheets 1, 3, 4
SLR-PB-M-381, Sheet 1
SLR-PB-M-397, Sheet 1
SLR-PB-M-399, Sheet 1

Table 2.3.3-19 Plant Equipment and Floor Drain System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components with Internal Coatings	Leakage Boundary
Pump Casing (Circulating Water Pump Structure Sump Pump)	Pressure Boundary
Pump Casing (Conveyor Floor Drain Sump Pump)	Leakage Boundary
Pump Casing (D/G Building Sump Pump)	Leakage Boundary
Pump Casing (Drywell Equipment Drain Sump Pump)	Leakage Boundary
Pump Casing (Drywell Floor Drains Sump Pump)	Leakage Boundary
Pump Casing (Floor Drain Collector Pump)	Leakage Boundary
Pump Casing (Laundry Drain Tank Pump)	Leakage Boundary
Pump Casing (Off Gas Stack Sump Pump)	Leakage Boundary
Pump Casing (RHR Sump Pump)	Leakage Boundary
Pump Casing (Radwaste Building Equipment Drain Sump Pump)	Leakage Boundary
Pump Casing (Radwaste Floor Drain Sump Pump)	Leakage Boundary
Pump Casing (Reactor Building Equipment Drain Sump Pump)	Leakage Boundary
Pump Casing (Reactor Building Floor Drain Sump Pump)	Leakage Boundary
Pump Casing (Recombiner Building Equipment Sump Pump)	Leakage Boundary
Pump Casing (Recombiner Building Floor Drain Sump Pump)	Leakage Boundary
Pump Casing (Turbine Building Equipment Drain Sump Pump)	Leakage Boundary
Pump Casing (Turbine Building Floor Drain Sump Pump)	Leakage Boundary
Tanks (Floor Drain Demin)	Leakage Boundary
Tanks (Floor Drain Surge Tank)	Leakage Boundary
Tanks (Laundry Drain Tank)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-19 Plant Equipment and Floor Drain System
Summary of Aging Management Evaluation

2.3.3.20 Post Accident Sampling System

Description

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

The Post Accident Sampling System is described in UFSAR Section 7.20. The Post Accident Sampling System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Post Accident Sampling System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Post Accident Sampling System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Post Accident Sampling System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Post Accident Sampling System contains nonsafety-related, liquid-filled lines and components in the Reactor Building and the Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

7.20.4.6

Second License Renewal Boundary Drawings

SLR-PB-M-319, Sheets 3, 4
SLR-PB-M-352, Sheets 1, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-372, Sheets 1, 2
SLR-PB-M-374, Sheets 1, 2

Table 2.3.3-20 Post Accident Sampling System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger - (Jet Pump Sample Cooler) Tubes	Leakage Boundary
Heat Exchanger - (PASS Liquid Sample Cooler) Tubes	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Tanks (PASS Water Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-20 Post Accident Sampling System
Summary of Aging Management Evaluation

2.3.3.21 Process Sampling System

Description

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

The Process Sampling System is described in UFSAR Section 10.20. The Process Sampling System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Process Sampling System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Process Sampling System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Process Sampling System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Process Sampling System includes nonsafety-related water filled lines in the Reactor Building, Turbine Building and Main Control Room Complex, and Radwaste Building and Reactor Auxiliary Bay that have the potential for spatial interactions (spray or leakage) with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.20

Second License Renewal Boundary Drawings

SLR-PB-M-314, Sheets 1, 2, 5, 6
SLR-PB-M-316, Sheets 1, 2, 3, 4
SLR-PB-M-326, Sheets 1, 2, 3, 6, 7, 10, 11, 12, 13
SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-353, Sheets 1, 3
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-355, Sheets 1, 3
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-364, Sheets 1, 2
SLR-PB-M-370, Sheets 1, 2, 3
SLR-PB-M-371, Sheets 2, 3, 4

Table 2.3.3-21 Process Sampling System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping, piping components	Leakage Boundary
Tanks (TBCCW HX Service Water Sample Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-21 Process Sampling System
Summary of Aging Management Evaluation

2.3.3.22 Pump Structure Ventilation System

Description

The central portion of the Circulating Water Pump Structure is a seismic Class I structure, which houses the high pressure service water pumps, emergency service water pumps, fire pumps, and service water screen wash pumps. The Pump Structure Ventilation System provides the ventilation supply and exhaust to these pump compartments. The ventilation system is supplied with standby power during the loss of offsite power. Redundant ventilation equipment is furnished in each compartment for uninterrupted service. Each pump room contains two safety-related 100 percent capacity supply fans, two safety-related 100 percent capacity exhaust fans, and one nonsafety-related steam unit heater.

Each pump room has a missile protected concrete intake air supply mixing box which contains an outdoor air damper and a return air damper. Air is exhausted to a missile protected concrete exhaust air plenum which contains an outdoor air damper and return air damper. These concrete elements are evaluated with the Circulating Water Pump Structure.

The Pump Structure Ventilation System is described in detail in UFSAR Section 10.14. The Pump Structure Ventilation System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Pump Structure Ventilation System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Pump Structure Ventilation System is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Pump Structure Ventilation System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Pump Structure Ventilation System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Maintain emergency temperature limits within areas containing safety-related components. The Pump Structure Ventilation System provides ventilation to the high pressure service water and emergency service water pumps compartments. 10 CFR 54.4(a)(1)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Pump Structure Ventilation System is relied upon to be operable during and following fire safe shutdown events. 10 CFR 54.4(a)(3)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Pump Structure Ventilation System is relied upon to be operable following a station blackout event. 10 CFR 54.4(a)(3)

UFSAR References

10.14

Second License Renewal Boundary Drawings

SLR-PB-M-392, Sheet 1

Table 2.3.3-22 Pump Structure Ventilation System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve Body	Pressure Boundary

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

Table 3.3.2-22 Pump Structure Ventilation System
Summary of Aging Management Evaluation

2.3.3.23 Radiation Monitoring System

Description

The Radiation Monitoring System is a system which monitors various processes and areas for radioactivity levels. Portions of the Radiation Monitoring System are common to both units. The Radiation Monitoring System consists of safety-related and nonsafety-related portions and is in scope for license renewal; however, nonsafety-related portions that are not required to perform intended functions are not in scope.

The safety-related radiation monitors included in the system are as follows:
- main steam line radiation
- reactor building ventilation exhaust
- refueling floor ventilation exhaust
- control room fresh air supply
- control room emergency ventilation supply
- drywell area high range radiation monitoring

The nonsafety-related portions of the system include:
- main stack radiation monitoring
- service water radiation monitoring
- offgas radiation monitoring
- area radiation monitoring
- vent stack radiation monitoring
- drywell and torus radiation monitoring
- high pressure service water radiation monitoring
- fuel pool radiation monitoring
- reactor building closed cooling water monitoring
- radwaste radiation monitoring

The main steam line radiation monitors detect the gamma radiation level exterior to the Main Steam lines. If an abnormal condition is detected, the Radiation Monitoring System provides an input to the mechanical vacuum pump trip circuit.

The reactor building ventilation exhaust radiation monitors detect the radiation in the Reactor Building ventilation exhaust duct prior to its discharge from the structure. The detectors are located on the exhaust duct upstream of the ventilation isolation valves. If an abnormal condition is detected, an input is provided to the Primary Containment Isolation System (PCIS) for use in the Reactor Building isolation circuit and Standby Gas Treatment System (SGTS) initiation circuit.

The refueling floor ventilation exhaust radiation monitors detect the radiation in the ventilation exhaust duct from the refueling floor. The detectors are located on the exhaust duct upstream of the ventilation isolation valves. If an abnormal condition is detected, an input is provided to the PCIS for use in the Reactor Building isolation circuit and SGTS initiation circuit.

The control room fresh air supply radiation monitors detect the radioactivity in the outside air supply to the control room. The ventilation is monitored to detect the amount of radioactive material entering the control room, to assure that personnel are not exposed to excessive doses. If an abnormal condition is detected, the Radiation Monitoring System provides an input to the control room HVAC system to initiate filtration of the ventilation supply air through the control room emergency ventilation system.

The control room emergency ventilation supply radiation monitors detect the radioactivity in the air supply to the control room, downstream of the control room emergency ventilation filters. The ventilation is monitored to detect the amount of radioactive material entering the control room to assure that personnel are not exposed to excessive doses. The radioactivity is continuously indicated locally and abnormal conditions are indicated and annunciated in the Control Room.

The drywell area high range radiation monitoring system includes equipment that monitors the area radiation in the Drywell following an accident. Plant operators use the Drywell radiation, along with other monitoring data, to assess the plant condition following an accident and to make decisions regarding accident abatement.

The main stack radiation monitoring system detects radioactivity during normal and accident conditions. If an abnormal condition is detected, an input is provided to the Primary Containment Isolation System (PCIS) for use in the containment purge valve closure circuit. The main stack radiation monitors are nonsafety-related equipment that perform a safety-related intended function.

The Radiation Monitoring System is described in detail in UFSAR Sections 7.12 and 7.13. The portions of the Radiation Monitoring System that are not in scope for second license renewal include offgas radiation monitoring, area radiation monitoring, vent stack radiation monitoring, and fuel pool radiation monitoring. All other portions of the Radiation Monitoring System listed above are in scope for second license renewal. The Radiation Monitoring System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

<u>Reason for Scope Determination</u>

The Radiation Monitoring System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Radiation Monitoring System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Radiation Monitoring System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Radiation Monitoring System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

<u>Intended Functions</u>

1. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Radiation Monitoring System monitors parameters for radiation level and initiates appropriate protective action to limit the potential release of radioactive materials if predetermined levels are exceeded. 10 CFR 54.4 (a)(1) and 10 CFR 54.4 (a)(2)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Radiation Monitoring System includes nonsafety-related piping components that have the potential for structural interaction with SSCs that perform a 10 CFR 54.4(a)(1) function. The Radiation Monitoring System also includes nonsafety-related liquid-filled piping components that have the potential for spatial interaction with safety-related SSCs. This includes the nonsafety-related portions of the system located within the Reactor Building, the Radwaste Building and Reactor Auxiliary Bay, and the Diesel Generator Building. 10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Radiation Monitoring System includes components contained in the Environmental Qualification of Electrical Equipment (B.3.1.3) program. 10 CFR 54.4(a)(3)

UFSAR References

7.1.1
7.12
7.13
7.20

Second License Renewal Boundary Drawings

SLR-PB-M-310, Sheets 2, 5
SLR-PB-M-314, Sheets 4, 8
SLR-PB-M-315, Sheets 1, 3, 6, 7
SLR-PB-M-316, Sheets 1, 3
SLR-PB-M-330, Sheet 1
SLR-PB-M-367, Sheets 1, 2
SLR-PB-M-370, Sheet 2
SLR-PB-M-372, Sheets 1, 2
SLR-PB-M-384, Sheet 1
SLR-PB-M-391, Sheets 1, 2

Table 2.3.3-23 Radiation Monitoring System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Hoses	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (HPSW Rad Monitor Sample Pump)	Leakage Boundary
Pump Casing (Main Stack Rad Monitor Sample Pumps)	Pressure Boundary
Tanks (HPSW Rad Monitor)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)

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

Table 3.3.2-23 Radiation Monitoring System
Summary of Aging Management Evaluation

2.3.3.24 Radwaste System

Description

The intended function of the Radwaste System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure-retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid-filled portions of the system located within the Reactor Building, the Radwaste Building and Reactor Auxiliary Bay, and the Turbine Building and Main Control Room Complex. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support license renewal intended functions, and is in scope only for potential spatial interaction. The license renewal Radwaste System consists of the following plant systems: the radwaste system, the liquid process and disposal system, the solid process and disposal system, and the radwaste solidification system.

The Radwaste System is described in UFSAR Sections 9.2 and 9.3. The Radwaste System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Radwaste System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Radwaste System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Radwaste System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Radwaste System contains nonsafety-related, water-filled lines in the Reactor Building, the Radwaste Building and Reactor Auxiliary Bay, and the Turbine Building and Main Control Room Complex which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

9.2
9.3

Second License Renewal Boundary Drawings

SLR-PB-M-326, Sheet 1
SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-356, Sheets 1, 2
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-368, Sheet 1
SLR-PB-M-369, Sheet 1
SLR-PB-M-370, Sheets 1, 2, 3
SLR-PB-M-371, Sheets 1, 2, 3, 4, 5, 7

Table 2.3.3-24 Radwaste System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Chemical Waste Pump)	Leakage Boundary
Pump Casing (Condensate Backwash Transfer Pump)	Leakage Boundary
Pump Casing (Condensate Decant Pump)	Leakage Boundary
Pump Casing (Condensate Sludge Discharge Mixing Pump)	Leakage Boundary
Pump Casing (Injection Pump)	Leakage Boundary
Pump Casing (RWCU Backwash Transfer Pump)	Leakage Boundary
Pump Casing (Sludge Sample Pump)	Leakage Boundary
Tanks (Chemical Waste Tank)	Leakage Boundary
Tanks (Filter Aid Tank)	Leakage Boundary
Tanks (Laundry Hot Water Heater)	Leakage Boundary
Tanks (Mixing Tank)	Leakage Boundary
Tanks (RWCU Filter Demin Backwash Receiving Tank)	Leakage Boundary
Tanks (Radwaste Bldg Personnel Decon Hot Water Heater)	Leakage Boundary
Tanks (Waste Collector Filter Demin)	Leakage Boundary
Tanks (Waste Surge Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-24 Radwaste System
Summary of Aging Management Evaluation

2.3.3.25 Reactor Building Closed Cooling Water System

Description

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

The Reactor Building Closed Cooling Water System is described in UFSAR Section 10.8. The Reactor Building Closed Cooling Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Building Closed Cooling Water System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Reactor Building Closed Cooling Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Building Closed Cooling Water System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Building Closed Cooling Water System contains nonsafety-related, water-filled lines in the Reactor Building and Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.8

Second License Renewal Boundary Drawings

SLR-PB-M-314, Sheets 3, 7
SLR-PB-M-316, Sheets 1, 3
SLR-PB-M-326, Sheets 1, 10, 11, 12, 13
SLR-PB-M-327, Sheets 2, 4
SLR-PB-M-333, Sheets 1, 2

SLR-PB-M-353, Sheets 1, 2, 3, 4
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-368, Sheet 1
SLR-PB-M-369, Sheet 1
SLR-PB-M-374, Sheets 1, 2

Table 2.3.3-25 Reactor Building Closed Cooling Water System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Compressor Housing (Instrument Nitrogen Compressor)	Leakage Boundary
Heat Exchanger - (Instrument Nitrogen Compressor Aftercooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Instrument Nitrogen Compressor Aftercooler) Tubes	Leakage Boundary
Heat Exchanger - (PASS Jet Pump and Liquid Sample Coolers) Shell Side Components	Leakage Boundary
Heat Exchanger - (RBCCW Heat Exchangers) Shell Side Components	Leakage Boundary
Heat Exchanger - (RWCU Non-Regenerative Heat Exchanger) Shell Side Components	Leakage Boundary
Heat Exchanger - (RWCU Pump Motor Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger - (Reactor Water Sample Heat Transfer Coil) Shell Side Components	Leakage Boundary
Hoses	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Insulated piping, piping components	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (RBCCW Pumps)	Leakage Boundary
Tanks (RBCCW Chemical Addition Tank)	Leakage Boundary
Tanks (RBCCW Head Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-25 Reactor Building Closed Cooling Water System Summary of Aging Management Evaluation

2.3.3.26 Reactor Water Cleanup System

Description

The Reactor Water Cleanup (RWCU) System maintains 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 RWCU System provides continuous purification of a portion of the recirculation flow. The processed fluid is returned to the reactor pressure vessel or to radwaste or to condensate storage tanks. Regenerative heat exchangers are provided to minimize heat loss from the system. The system can be operated at any time during planned operations. The RWCU System is operated to maintain the reactor water quality to within specified limits.

The RWCU System also provides process flow to the noble metals monitoring system. The noble metals monitoring system provides indication of the effectiveness of noble metals to mitigate stress corrosion cracking (SCC) initiation and existing SCC growth on reactor pressure vessel wetted internal components and associated piping.

The RWCU System is described in UFSAR Section 4.9. The RWCU System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Reactor Water Cleanup System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Reactor Water Cleanup System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Water Cleanup System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Reactor Water Cleanup System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The RWCU System contains nonsafety-related, water-filled lines in the Reactor Building and the Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). The RWCU System includes valves that are high/low pressure interfaces which are credited for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

UFSAR References

4.9

Second License Renewal Boundary Drawings

SLR-PB-M-326, Sheet 14
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-355, Sheets 1, 2, 3, 4
SLR-PB-M-370, Sheet 1
SLR-PB-M-371, Sheets 1, 3, 4

Table 2.3.3-26 Reactor Water Cleanup System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger - (RWCU Non-Regenerative Heat Exchanger) Tube Side Components	Leakage Boundary
Heat Exchanger - (RWCU Pump Motor Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (RWCU Regenerative Heat Exchanger) Shell Side Components	Leakage Boundary
Heat Exchanger - (RWCU Regenerative Heat Exchanger) Tube Side Components	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Piping, piping components outboard the second containment isolation valves with a diameter greater than or equal to 4" NPS	Leakage Boundary
Pump Casing (RWCU Filter Demineralizer Holding Pump)	Leakage Boundary
Pump Casing (RWCU Filter Demineralizer Precoat Pump)	Leakage Boundary
Pump Casing (RWCU Pump)	Leakage Boundary
Tanks (RWCU Filter Demineralizer Precoat Tank)	Leakage Boundary
Tanks (RWCU Filter Demineralizer)	Leakage Boundary
Tanks (Slurry Prep Tank)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-26 Reactor Water Cleanup System
Summary of Aging Management Evaluation

2.3.3.27 Refueling Water Storage and Transfer System

Description

The Refueling Water Storage and Transfer System supplies condensate from the Refueling Water Storage Tank (RWST) to fill the reactor well and the dryer-separator storage pit during unit refueling operations. The RWST can also be used as a makeup water source to the spent fuel pool.

Due to the implementation of Extended Power Uprate (EPU), the Condensate Storage Tank (CST) is utilized as the sole suction source for High Pressure Coolant Injection/Reactor Core Isolation Cooling (HPCI/RCIC) systems during Station Blackout (SBO), Anticipated Transient Without Scram (ATWS) and Appendix R events. The volume of the RWST is required to supplement the CST for the Appendix R and ATWS events.

The Refueling Water Storage and Transfer System is described in UFSAR Sections 10.3.4.2 and 10.5. The Refueling Water Storage and Transfer System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Refueling Water Storage and Transfer System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Refueling Water Storage and Transfer System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Refueling Water Storage and Transfer System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Anticipated Transient Without Scram (10 CFR 50.62). The Refueling Water Storage and Transfer System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Refueling Water Storage and Transfer System contains nonsafety-related, water-filled lines in the Reactor Building, the Turbine Building and Main Control Room Complex, and the Radwaste Building and Reactor Auxiliary Bay which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The RWST inventory supplements the CST volume which is the suction source for the HPCI and RCIC systems for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The RWST inventory supplements the CST volume which is the suction source for the HPCI and RCIC systems for the ATWS event. 10 CFR 54.4(a)(3)

UFSAR References

10.3.4.2
10.5
Appendix C.1.3

Second License Renewal Boundary Drawings

SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-311, Sheets 1, 7
SLR-PB-M-325, Sheet 1
SLR-PB-M-363, Sheets 1, 2

Table 2.3.3-27 Refueling Water Storage and Transfer System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Insulated Valve Body	Pressure Boundary
Insulated piping, piping components	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Pump Casing (Refueling Water Pumps)	Pressure Boundary
Tanks (Refueling Water Storage Tank)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.3.2-27 Refueling Water Storage and Transfer System Summary of Aging Management Evaluation

2.3.3.28 Safety Grade Instrument Gas System

Description

The Safety Grade Instrument Gas (SGIG) System supplies pressurized nitrogen gas from the containment atmospheric dilution tank as a backup to normal instrument air. The safety grade pneumatic supply is isolated from the nonsafety grade portion of the air supply by spring-loaded, soft-seat, check valves designed for zero leakage.

Following a LOCA coincident with a loss of instrument air, the SGIG System supplies pressurized nitrogen gas as a backup pneumatic source to the containment atmospheric control purge and vent isolation valves, torus to secondary containment vacuum breakers, and the containment atmospheric dilution vent control valves. The SGIG System also supplies nitrogen gas to non-ADS SRV's 071E, H, and J.

The SGIG System is described in UFSAR Sections 5.2.3.9 and 10.17. The SGIG System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Safety Grade Instrument Gas System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Safety Grade Instrument Gas System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Safety Grade Instrument Gas System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Safety Grade Instrument Gas System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide motive power to safety-related components. The SGIG System provides a safety-related backup supply of pressurized nitrogen for the operation of various isolation valves, vacuum breakers, and control valves following a design basis accident. 10 CFR 54.4(a)(1)

2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The SGIG System contains nonsafety-related components relied upon to preserve the structural support intended function of the system. 10 CFR 54.4(a)(2)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The SGIG System is credited for fire safe shutdown, and provides a backup supply of nitrogen to certain SRVs to enable their operation during a fire in certain areas of the plant. 10 CFR 54.4(a)(3)

UFSAR References

5.2.3.9
10.17

Second License Renewal Boundary Drawings

SLR-PB-M-327, Sheets 1, 3
SLR-PB-M-333, Sheets 1, 2
SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-353, Sheets 1, 3
SLR-PB-M-361, Sheets 1, 2, 3, 4
SLR-PB-M-362, Sheets 1, 2
SLR-PB-M-367, Sheets 1, 2, 3
SLR-PB-M-372, Sheets 1, 2

Table 2.3.3-28 Safety Grade Instrument Gas System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Hoses	Pressure Boundary
Piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Strainer (Element)	Filter
Valve Body	Pressure Boundary
	Structural Integrity (Attached)

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

Table 3.3.2-28 Safety Grade Instrument Gas System
Summary of Aging Management Evaluation

2.3.3.29 Service Water System

Description

The Service Water System consists of three one-half capacity service water pumps, three horizontal fuel pool service water booster pumps, and associated heat exchangers, piping, valves, and instrumentation. Return headers in each unit return the water to the discharge pond. The system supplies cooling water to the Fuel Pool Cooling and Cleanup System heat exchangers, Reactor Building Closed Cooling Water (RBCCW) System heat exchangers, Turbine Building Closed Cooling Water (TBCCW) System heat exchangers, and other plant nonsafety-related heat exchangers. In addition, the Service Water System supplies cooling water to the Residual Heat Removal (RHR)System pump room coolers, High Pressure Coolant Injection (HPCI) System pump room coolers, Core Spray System pump room coolers, the Reactor Core Isolation Cooling (RCIC) System pump room coolers, the RHR System pump seal coolers, and the Core Spray System pump motor oil coolers when off-site power is available. During loss of offsite power, the Emergency Service Water (ESW) System provides the cooling water to these safety-related heat exchangers.

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

The Service Water System is described in UFSAR Section 10.6. The Service Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Service Water System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Service Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Service Water System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Service Water System includes nonsafety-related water filled lines in the Reactor Buildings, the Radwaste Building and Reactor Auxiliary Bay, and areas of the Turbine Building and Main Control Room Complex and the Administration Building and

Shop that are near safety-related equipment that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.6

Second License Renewal Boundary Drawings

SLR-PB-M-314, Sheets 1, 2, 3, 4, 5, 6, 7, 8, 9
SLR-PB-M-315, Sheets 4, 5
SLR-PB-M-325, Sheet 5
SLR-PB-M-363, Sheets 1, 2
SLR-PB-M-370, Sheet 2

Table 2.3.3-29 Service Water System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger - (Fuel Pool Cooling Heat Exchanger) Tube Side Components	Leakage Boundary
Heat Exchanger - (RBCCW Heat Exchangers) Tube Side Components	Leakage Boundary
Heat Exchanger - (Radwaste Building Heating System Condensate Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tube Sheet	Leakage Boundary
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tubes	Leakage Boundary
Heat Exchanger - (Turbine Building Closed Cooling Water Heat Exchanger) Tube Side Components	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Insulated piping, piping components	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Fuel Pool Service Water Booster Pump)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-29 Service Water System
Summary of Aging Management Evaluation

2.3.3.30 Standby Liquid Control System

Description

The purpose of the Standby Liquid Control (SLC) System is to provide a backup method, which is redundant with, and independent of, the control rod drive system to shutdown the reactor and maintain it in a cold, subcritical condition. Maintaining subcriticality as the nuclear system cools assures that the fuel barrier is not threatened by overheating in the event that insufficient negative reactivity is inserted by control rods to counteract the positive reactivity effects of a decrease in the moderator temperature. A neutron absorber consisting of enriched sodium pentaborate in solution is injected into the vessel and distributed throughout the core in sufficient quantity to achieve and maintain shutdown while allowing for margin due to leakage and imperfect mixing.

The system consists of a solution storage tank, a test tank, two 100 percent capacity positive displacement pumps with their associated relief valves and accumulators, two explosive valves installed in parallel at the pump discharge, and associated controls and instrumentation. The system is manually initiated from the control room via a three-position key-locked selector switch.

The SLC System is described in detail in UFSAR Section 3.8. The SLC System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Standby Liquid Control System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Standby Liquid Control System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Standby Liquid Control System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) and Anticipated Transient Without Scram (10 CFR 50.62). The Standby Liquid Control System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) or Station Blackout (10 CFR 50.63).

Intended Functions

1. Introduce emergency negative reactivity to make the reactor subcritical. The SLC System provides backup capability for reactivity control, independent of normal reactivity control provisions in the nuclear reactor, to be able to shutdown the reactor if the normal control ever becomes inoperative. 10 CFR 54.4(a)(1)

2. Control and treat radioactive materials released to the secondary containment. In the event of a Loss of Coolant Accident, the SLC System is manually initiated from the control room to pump sodium pentaborate into the reactor to maintain suppression pool pH at a level of 7.0 or higher to minimize iodine releases from primary containment to the environment.
10 CFR 54.4(a)(1)

3. Provide reactor coolant pressure boundary. The SLC System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

4. Provide primary containment boundary. The SLC System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The SLC System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial and structural interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The SLC System injects sodium pentaborate solution into the reactor to achieve shutdown for mitigation of an ATWS. 10 CFR 54.4(a)(3)

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

UFSAR References

3.8

Second License Renewal Boundary Drawings

SLR-PB-M-351, Sheets 1, 3
SLR-PB-M-352, Sheets 1, 3
SLR-PB-M-358, Sheets 1, 2

Table 2.3.3-30 Standby Liquid Control System
Components Subject to Aging Management Review

Component Type	Intended Function
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Drip Pan (Trough)	Leakage Boundary
Gearbox (Standby Liquid Control Pump)	Pressure Boundary
Piping elements	Leakage Boundary
	Pressure Boundary
Piping, piping components	Leakage Boundary
	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary
Strainer (Element)	Filter
Tanks (Standby Liquid Control Tank)	Pressure Boundary
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

Table 3.3.2-30 Standby Liquid Control System
Summary of Aging Management Evaluation

2.3.3.31 Suppression Pool Temperature Monitoring System

Description

The Suppression Pool Temperature Monitoring System (SPOTMOS) provides indication of the individual and average bulk torus water temperature in the control room to ensure torus water is maintained within specified temperature limits. The system also provides indication of torus water temperature to the remote shutdown panel and the high pressure coolant injection alternative control station for remote indication when the control room is not accessible. The drywell temperature monitoring instrumentation credited for FSSD associated with the Drywell Ventilation System are evaluated with the Suppression Pool Temperature Monitoring System.

The SPOTMOS consists of two independent divisionalized monitoring systems. Each system consists of temperature sensors and a processing unit to display temperature in the control room.

Within each divisionalized system, SPOTMOS is capable of providing individual as well as the average of the temperature sensor indications.

The SPOTMOS is normally energized and is supplied from independent divisionalized Class 1E power sources.

The SPOTMOS is described in detail in UFSAR Section 7.20.4.7. The SPOTMOS boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Suppression Pool Temperature Monitoring System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Suppression Pool Temperature Monitoring System is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Suppression Pool Temperature Monitoring System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and 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), and Station Blackout (10 CFR 50.63). The Suppression Pool Temperature Monitoring System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide primary containment boundary. The Suppression Pool Temperature Monitoring System includes piping components that are part of the primary containment boundary. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Suppression Pool Temperature Monitoring System includes instrumentation that provides signals to ensure suppression pool temperature is maintained within specified limits. 10 CFR 54.4(a)(1)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Suppression Pool Temperature Monitoring System is credited to provide suppression pool and drywell temperature indication for Fire Safe Shutdown. 10 CFR 54.4(a)(3)

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

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Suppression Pool Temperature Monitoring System is credited to provide suppression pool and drywell temperature indication for Station Blackout. 10 CFR 54.4(a)(3)

UFSAR References

7.20.4.7

Second License Renewal Boundary Drawings

SLR-PB-M-361, Sheets 1, 2, 3, 4

Table 2.3.3-31 Suppression Pool Temperature Monitoring System Components Subject to Aging Management Review

Component Type	Intended Function
Piping, piping components	Pressure Boundary

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

Table 3.3.2-31 Suppression Pool Temperature Monitoring System Summary of Aging Management Evaluation

2.3.3.32 Torus Water Cleanup System

Description

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

The Torus Water Cleanup System is not described in the UFSAR. The Torus Water Cleanup System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Torus Water Cleanup System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Torus Water Cleanup System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Torus Water Cleanup System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Torus Water Cleanup System contains nonsafety-related, water-filled lines in the Turbine Building and Main Control Room Complex and the Reactor Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

None

Second License Renewal Boundary Drawings

SLR-PB-M-307, Sheets 1, 4
SLR-PB-M-361, Sheets 2, 4
SLR-PB-M-362, Sheets 1, 2

Table 2.3.3-32 Torus Water Cleanup System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping, piping components	Leakage Boundary
Pump Casing (Torus Water Filter Pump)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-32 Torus Water Cleanup System
Summary of Aging Management Evaluation

2.3.3.33 Torus Water Storage and Transfer System

Description

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

The Torus Water Storage and Transfer System is described in UFSAR Section 10.19.3.5. The Torus Water Storage and Transfer System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Torus Water Storage and Transfer System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Torus Water Storage and Transfer System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Torus Water Storage and Transfer System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Torus Water Storage and Transfer System contains nonsafety-related, water-filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.19.3.5

Second License Renewal Boundary Drawings

SLR-PB-M-311, Sheets 1, 7

Table 2.3.3-33 Torus Water Storage and Transfer System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Hoses	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Torus Dewatering Pump)	Leakage Boundary
Pump Casing (Torus Sludge Pump)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-33 Torus Water Storage and Transfer System
Summary of Aging Management Evaluation

2.3.3.34 Traveling Water Screen System

Description

The Peach Bottom Traveling Water Screen System includes the following plant systems: the traveling water screens, the circulating water screen wash system, the service water screen wash system, the outer screen structure screen wash system, the circulating water traveling screen grease system, the service water traveling screen grease system, the outer traveling screen grease system, the deicing air system, and the trash rakes. The circulating water, service water, and the outer screen structure screen wash systems pump water to remove collected debris on the traveling screens for disposal. The de-icing air system uses compressed air to breaks up surface ice formations at the inlet side of the outer screen structure. The trash racks prevent the introduction of large debris from entering the outer screen structure. The traveling screen grease systems have been abandoned in place.

The Traveling Water Screen System is described in UFSAR Section 11.6. The Traveling Water Screen System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Traveling Water Screen System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Traveling Water Screen System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Traveling Water Screen System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Traveling Water Screen System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Traveling Water Screen System includes nonsafety-related water filled lines in the Circulating Water Pump Structure that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs.
10 CFR 54.4(a)(2)

2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). The Traveling Water Screen System service water traveling screens (2(3)A(B)008) perform the design function specified in NFPA 20 by filtering water that enters the fire protection pumps to remove debris that could potentially degrade the performance of the fire pumps.
10 CFR 54.4(a)(3)

UFSAR References

10.6
10.9
11.6

Second License Renewal Boundary Drawings

SLR-PB-M-313, Sheets 1, 2

Table 2.3.3-34 Traveling Water Screen System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flexible Connection	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Service Water Traveling Screen Wash Pump)	Leakage Boundary
Traveling Screen	Filter
Valve Body	Leakage Boundary

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

Table 3.3.2-34 Traveling Water Screen System
Summary of Aging Management Evaluation

2.3.3.35 Turbine Building Closed Cooling Water System

Description

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

The Turbine Building Closed Cooling Water System is described in UFSAR Section 10.10. The Turbine Building Closed Cooling Water System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Turbine Building Closed Cooling Water System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Turbine Building Closed Cooling Water System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Turbine Building Closed Cooling Water System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Turbine Building Closed Cooling Water System contains nonsafety-related, water-filled lines in the Turbine Building and Main Control Room Complex which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.10

Second License Renewal Boundary Drawings

SLR-PB-M-316, Sheets 2, 4
SLR-PB-M-320, Sheets 5, 6, 26

Table 2.3.3-35 Turbine Building Closed Cooling Water System Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Compressor Housing (Condensate Backwash System Air Compressor)	Leakage Boundary
Compressor Housing (Radwaste Air Compressor)	Leakage Boundary
Heat Exchanger - (Condensate Backwash System Air Compressor Aftercooler) Shell Side Components	Leakage Boundary
Heat Exchanger - (Condensate Backwash System Air Compressor Intercooler) Shell Side Components	Leakage Boundary
Heat Exchanger - (Radwaste Air Compressor Aftercooler) Shell Side Components	Leakage Boundary
Heat Exchanger - (Turbine Building Closed Cooling Water Heat Exchanger) Shell Side Components	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Insulated piping, piping components	Leakage Boundary
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Pump Casing (Turbine Building Closed Cooling Water Pump)	Leakage Boundary
Tanks (TBCCW Chemical Addition Tank)	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.3.2-35 Turbine Building Closed Cooling Water System Summary of Aging Management Evaluation

2.3.3.36 Water Treatment System

Description

The intended function of the Water Treatment System for license renewal is to maintain leakage boundary integrity to preclude system interactions in the reactor building, turbine building, radwaste building, circulating water pump structure, and diesel generator building. For this reason, this system's pressure-retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. The license renewal Water Treatment System consists of the following plant systems: the water treatment system, the raw water system, the makeup water system, the demineralized water system, the ecolochem demineralizer skid, and the raw water systems chemical injection. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support other license renewal intended functions, and is in scope only for potential spatial interaction.

The Water Treatment System is described in UFSAR Section 10.16 and 10.18. The Water Treatment System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Water Treatment System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Water Treatment System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Water Treatment System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Water Treatment System includes nonsafety-related water filled lines in the Circulating Water Pump Structure, the Diesel Generator Building, the Radwaste Building and Reactor Auxiliary Bay, the Reactor Buildings, and areas of the Turbine Building and Main Control Room Complex that are near safety-related equipment that have the potential for spatial interactions (spray or leakage) or structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

10.16
10.18

Second License Renewal Boundary Drawings

SLR-PB-M-310, Sheets 2, 4
SLR-PB-M-314, Sheets 1, 5
SLR-PB-M-315, Sheets 1, 3
SLR-PB-M-316, Sheets 1, 3
SLR-PB-M-319, Sheets 2, 3, 4
SLR-PB-M-326, Sheets 1, 2, 6
SLR-PB-M-358, Sheets 1, 2
SLR-PB-M-370, Sheet 2
SLR-PB-M-371, Sheets 5, 7
SLR-PB-M-377, Sheet 2

Table 2.3.3-36 Water Treatment System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping, piping components	Leakage Boundary
	Structural Integrity (Attached)
Valve Body	Leakage Boundary

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

Table 3.3.2-36 Water Treatment System
Summary of Aging Management Evaluation

2.3.4 STEAM AND POWER CONVERSION SYSTEM

The following systems are addressed in this section:

- Condensate System (2.3.4.1)
- Condensate Storage System (2.3.4.2)
- Feedwater System (2.3.4.3)
- Main Condenser System (2.3.4.4)
- Main Steam System (2.3.4.5)

2.3.4.1 Condensate System

Description

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

The Condensate System is described in UFSAR Sections 3.4.5.2, 11.7 and 11.8. The Condensate System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Condensate System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. The Condensate System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Condensate System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Condensate System contains nonsafety-related, water-filled lines in the Turbine Building and Main Control Room Complex and the Reactor Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

UFSAR References

1.6.1.4.6
1.6.1.4.7
3.4.5.2
11.7
11.8

Second License Renewal Boundary Drawings

SLR-PB-M-307, Sheets 1, 2, 3, 4, 5, 6
SLR-PB-M-311, Sheets 1, 6, 7, 12, 15, 17
SLR-PB-M-331, Sheets 1, 3
SLR-PB-M-361, Sheets 2, 4
SLR-PB-M-362, Sheets 1, 2

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

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary
Piping, piping components	Leakage Boundary
Valve Body	Leakage Boundary

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

Table 3.4.2-1 Condensate System
Summary of Aging Management Evaluation

2.3.4.2 Condensate Storage System

Description

The Condensate Storage System is the preferred water supply for the High Pressure Coolant Injection System (HPCI) and the Reactor Core Isolation Cooling System (RCIC). The system also provides plant system makeup needs and provides condensate for any continuous service needs.

The system consists of two 200,000 gallon capacity (one for each unit) condensate storage tanks (CSTs) and associated piping and valves necessary to complete required system functions. The Condensate Storage System is credited to supply the HPCI and RCIC systems during fire safe shutdown, station blackout, and ATWS scenarios.

The Condensate Storage System is described in UFSAR Sections 4.7, 6.4, 6.5.3, and 11.7. The Condensate Storage System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Condensate Storage System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Condensate Storage System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Condensate Storage System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). The Condensate Storage System is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49).

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Condensate Storage System includes safety-related piping between the condensate storage tanks and the HPCI, RCIC, and Core Spray System pumps. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Condensate Storage System includes safety-related level instrumentation that provides a signal to realign the HPCI and RCIC pump suction from the CST to the suppression pool, when CST water level reaches prescribed low level limits. 10 CFR 54.4(a)(1)

3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Condensate Storage System contains nonsafety-related, water-filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs. The Condensate Storage System also contains nonsafety-related lines relied upon to preserve the structural support intended function of the system. 10 CFR 54.4(a)(2)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The CST is the credited suction source for the HPCI and RCIC systems for Fire Safe Shutdown.
10 CFR 54.4(a)(3)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The CST is the credited suction source for the HPCI and RCIC systems for SBO coping and recovery.
10 CFR 54.4(a)(3)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The CST is the credited suction source for the HPCI and RCIC systems for the ATWS scenario. 10 CFR 54.4(a)(3)

UFSAR References

3.4.5
4.7
6.4
6.5.3
7.4
10.3
11.7

Second License Renewal Boundary Drawings

SLR-PB-M-309, Sheets 1, 2
SLR-PB-M-325, Sheet 1
SLR-PB-M-362, Sheets 1, 2

Table 2.3.4-2 Condensate Storage System
Components Subject to Aging Management Review

Component Type	**Intended Function**
Bolting (Closure)	Mechanical Closure
Insulated Valve Body	Pressure Boundary
	Structural Integrity (Attached)
Insulated piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Tanks (Condensate Storage Tank)	Pressure Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

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

Table 3.4.2-2 Condensate Storage System
Summary of Aging Management Evaluation

2.3.4.3 Feedwater System

Description

The Feedwater System is safety-related from the RPV to the outboard primary containment isolation valves. The portion of the Feedwater System from the outboard primary containment isolation valve to the inlet of the drain cooler is nonsafety-related.

During normal plant operation, the Feedwater System receives its supply of water from the outlet of the condensate demineralizers. The system consists of three feedwater heater strings (with cascading drains) connected in parallel, each consisting of five low pressure feedwater heaters and one drain cooler in series. The feedwater heaters receive steam from the main turbine system and preheat feedwater prior to entering the reactor feed pumps, thus increasing the heat cycle efficiency. The outlets of the three heater strings are cross-connected and provide a common suction header for the three reactor feed pumps. The reactor feed pumps are mounted in parallel with each having an individual suction valve, discharge check valve, and discharge valve. The reactor feed pumps discharge to a common discharge header that connects to two feedwater headers. These two feedwater headers contain inboard and outboard primary containment isolation valves. Inside containment, these two feedwater headers each split into three piping runs for a total of six, which then go to the RPV. The Feedwater System provides the injection path for HPCI and RCIC during transient and accident conditions. HPCI and RCIC join the Feedwater System outside the primary containment. Flow is then channeled through the feedwater piping to the RPV.

The Feedwater System is described in UFSAR Sections 4.11, 7.10, and 11.8. The Feedwater System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Feedwater System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Feedwater System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Feedwater System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Feedwater System provides an injection path into the reactor pressure vessel for HPCI. 10 CFR 54.4(a)(1)

2. Remove residual heat from the reactor coolant system. The Feedwater System provides an injection path into the reactor pressure vessel for HPCI and RCIC. 10 CFR 54.4(a)(1)

3. Provide reactor coolant pressure boundary. The Feedwater System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)

4. Provide primary containment boundary. The Feedwater System includes primary containment isolation valves. 10 CFR 54.4(a)(1)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Feedwater System contains nonsafety-related, water-filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs. The Feedwater System also contains nonsafety-related lines relied upon to preserve the structural support intended function of the system. Additionally, the feedwater lines upstream of the outer isolation check valves to the first remotely operated stop valve in the feedwater pump discharge are designed to meet the stress requirements of seismic Class I piping. 10 CFR 54.4(a)(2)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Feedwater System provides an injection path into the reactor pressure vessel for both HPCI and RCIC. 10 CFR 54.4(a)(3)

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Feedwater System provides an injection path into the reactor pressure vessel for both HPCI and RCIC. 10 CFR 54.4(a)(3)

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

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Feedwater System provides an injection path into the reactor pressure vessel for both HPCI and RCIC. 10 CFR 54.4(a)(3)

UFSAR References

4.7
4.11
6.4.1
7.3
7.10
11.8

Second License Renewal Boundary Drawings

SLR-PB-M-308, Sheets 1, 3
SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-354, Sheets 1, 2
SLR-PB-M-359, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2

Table 2.3.4-3 Feedwater System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Piping, piping components	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (Reactor Feed Pumps)	Structural Integrity (Attached)
Valve Body	Leakage Boundary
	Pressure Boundary
	Structural Integrity (Attached)
Valve Body (Class 1)	Pressure Boundary

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

Table 3.4.2-3 Feedwater System
Summary of Aging Management Evaluation

2.3.4.4 Main Condenser System

Description

The Main Condenser System provides a heat sink for the turbine exhaust steam, turbine bypass steam, and other flows. It also deaerates and stores the condensate for reuse after a period of radioactive decay. Additionally, the Main Condenser System provides for post-accident containment, holdup of MSIV bypass leakage.

The main condenser is a single pass, single pressure, deaerating type with a reheating deaerating hotwell and divided waterboxes. The condenser consists of three sections, each section located below the low-pressure elements of the turbine, with the tubes oriented transverse to the turbine-generator axis. The steam exhausts directly down into the condenser shells through exhaust openings in the bottom of each low-pressure turbine casing. The condensers also receive steam from the reactor feed pump turbines.

PBAPS accident analyses evaluated MSIV bypass leakage as part of primary containment leakage. This leakage is treated as a ground level release, with credit for holdup (elemental and particulate iodine only) in the main condenser. This leakage is to the main condenser, which is assumed to leak at one percent of volume per day.

The Main Condenser System is described in UFSAR Sections 11.3 and 14.9. The Main Condenser System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Main Condenser System is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related and relied upon to remain functional during and following design basis events. The Main Condenser System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Main Condenser System is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Post-accident containment holdup of MSIV bypass leakage. The main condenser provides for post-accident containment holdup of MSIV bypass leakage. 10 CFR 54.4(a)(2)

UFSAR References

11.3
14.9.2

Second License Renewal Boundary Drawings

SLR-PB-M-303, Sheets 2, 4
SLR-PB-M-304, Sheets 1, 2
SLR-PB-M-306, Sheets 1, 2
SLR-PB-M-307, Sheets 1, 2, 4, 5

Table 2.3.4-4 Main Condenser System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joint	Holdup
Heat Exchanger - (Main Condenser) Tube Sheet	Holdup
Heat Exchanger - (Main Condenser) Tubes	Holdup
Heat Exchanger - (Main Condenser, Feedwater Heaters, and Drain Coolers) Shell Side Components	Holdup
Piping, piping components	Holdup
Rupture Disks	Holdup
Turbine Casings	Holdup

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

Table 3.4.2-4 Main Condenser System
Summary of Aging Management Evaluation

2.3.4.5 Main Steam System

Description

The Main Steam System provides steam from the reactor pressure vessel through the primary containment to the high pressure turbine over the full range of reactor power operation. Four steam lines are utilized between the reactor pressure vessel and the high pressure turbine. Each main steam line from the reactor nozzle up to and including the MSIV external to the primary containment is seismic Class I and part of the reactor coolant pressure boundary.

The Main Steam System provides steam on demand to the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) System turbines via the "B" and "C" main steam lines, respectively.

Overpressure protection of the reactor pressure vessel is provided via the main steam safety relief valves MSRVs and safety valves (SVs). This function ensures the integrity of the reactor coolant pressure boundary and associated piping.

The Main Steam System includes the automatic depressurization system (ADS) which is an ECCS. Five designated safety relief valves fulfill the ECCS function to ensure that the low pressure ECCSs provide adequate core cooling during accident and post-accident conditions in the event that the high pressure coolant injection systems are unavailable or unable to maintain level in the vessel.

The Main Steam System operates in conjunction with the primary containment isolation system to mitigate the consequences of accidents which could result in potential offsite exposure due to a breach of the main steam system. The MSIVs will close on signals indicative of a LOCA or leak in the main steam system to containment. The main steam line flow restrictors limit the loss of coolant from the reactor coolant pressure boundary prior to MSIV closure following a steam line rupture outside of containment.

The Main Steam System also allows for a path for alternate shutdown cooling in the event that the shutdown cooling mode of the Residual Heat Removal (RHR) System cannot be established. This is accomplished by closure of the MSIVs, raising the reactor vessel level to the main steam lines, and using no more than two ADS SRVs for low pressure liquid discharge to the suppression pool, and one or more RHR loops operating in the suppression pool cooling mode of the system.

Post-accident containment, holdup and plateout of MSIV bypass leakage is credited in accident analyses when calculating airborne activities. Plateout and holdup are credited in the steam line piping for a LOCA.

Portions of the Main Steam System are located in the vicinity of safety-related SSCs in the Reactor Building. The intended function of these portions of the Main Steam System is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of the safety-related functions of the safety-related SSC.

The Main Steam System is described in UFSAR Sections 4.4, 4.5, 4.6, 4.11, 6.4, and 7.4. The Main Steam System boundaries for second license renewal are shown on the second license renewal boundary drawings listed below.

Reason for Scope Determination

The Main Steam System meets 10 CFR 54.4(a)(1) because it is a safety-related system that is relied upon to remain functional during and following design basis events. The Main Steam System meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Main Steam System also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide emergency heat removal from primary containment and provide containment pressure control. The MSRV discharge quenchers condense the steam from MSRV operation to minimize pressure and thermal effects on the primary containment during plant events. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals for reactor trip or engineered safety functions. The ADS uses drywell pressure, reactor water level sensor inputs and emergency core cooling pump pressure indication, arranged in trip systems, to initiate automatic depressurization. Additionally, Main Steam process conditions provide input signals to the Primary Containment Isolation System and the reactor protection system. 10 CFR 54.4 (a)(1)

3. Provide reactor coolant pressure boundary. The Main Steam System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building. The Main Steam System, in conjunction with the Reactor Protection System, provides overpressure protection for the reactor pressure vessel and the Reactor Recirculation System. The main steam flow restrictors limit the loss of coolant from the reactor coolant pressure boundary prior to MSIV closure following a steam line rupture outside of containment. 10 CFR 54.4(a)(1)

4. Provide primary containment boundary. The Main Steam System containment isolation valves close automatically on isolation signals. 10 CFR 54.4(a)(1)

5. Provide emergency core cooling where the equipment provides cooling directly to the core. The ADS functions to depressurize the reactor pressure vessel to allow low pressure emergency core cooling systems to inject if high pressure systems are unavailable. The Main Steam System also delivers steam to the HPCI and RCIC systems as a motive force for the turbines. 10 CFR 54.4(a)(1)

6. Post-accident containment holdup and plateout of MSIV bypass leakage. The main steam lines are credited with holdup and plateout of MSIV leakage following a LOCA. Routing of the MSIV leakage through main steam line drains to the main condenser permits additional plateout and holdup in the main condenser. 10 CFR 54.4(a)(2)

7. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Nonsafety-related portions of the Main Steam System are located in the Reactor Building which have the potential to structurally interact with safety-related SSCs. 10 CFR 54.4(a)(2)

8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Fire Protection (10 CFR 50.48). The Main Steam System provides the flow path and maintains the pressure boundary for reactor safe shutdown. The MSRV discharge quenchers condense the steam from MSRV operation to minimize pressure and thermal effects on the primary containment during fire related events. Additionally, ADS control and operation are credited in support of post fire safe shutdown. 10 CFR 54.4(a)(3)

9. Relied upon in safety analyses of plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Environmental Qualification (10 CFR 50.49). The Main Steam large branch piping isolation valves are expected to operate in a harsh post LOCA environment. The Main Steam System includes components that are environmentally qualified. 10 CFR 54.4(a)(3)

10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Station Blackout (10 CFR 50.63). The Main Steam System provides the flow path and maintains the pressure boundary for reactor safe shutdown. The MSRV discharge quenchers condense the steam from MSRV operation to minimize pressure and thermal effects on the primary containment during station blackout. Additionally, ADS supports the depressurization of the reactor, to support maintaining suppression pool temperatures for coping during a station blackout. 10 CFR 54.4(a)(3)

11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for ATWS (10 CFR 50.62). The Main Steam System provides overpressure protection by directing steam through the MSRVs to the suppression pool during an ATWS. 10 CFR 54.4(a)(3)

UFSAR References

4.4
4.5
4.6
4.10
4.11
6.4
7.4.3.3
14.9.2

Second License Renewal Boundary Drawings

SLR-PB-M-303, Sheets 1, 2, 3
SLR-PB-M-304, Sheet 2
SLR-PB-M-306, Sheet 2
SLR-PB-M-308, Sheets 2, 4
SLR-PB-M-310, Sheet 1
SLR-PB-M-331, Sheets 1, 3
SLR-PB-M-351, Sheets 1, 2, 3, 4
SLR-PB-M-359, Sheets 1, 2
SLR-PB-M-365, Sheets 1, 2

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

Component Type	Intended Function
Accumulator (MSIV Accumulators)	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device (Class 1)	Pressure Boundary
	Throttle
Piping, piping components	Holdup and Plateout
	Pressure Boundary
	Structural Integrity (Attached)
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary
Valve Body	Holdup and Plateout
	Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

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

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

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

The following structures and commodity groups are addressed in this section:

- Administration Building and Shop (2.4.1)
- Boiler House (2.4.2)
- Circulating Water Pump Structure (2.4.3)
- Component Supports (2.4.4)
- Containment Structure (2.4.5)
- Dewatering Building (2.4.6)
- Diesel Generator Building (2.4.7)
- Electrical and Instrumentation Enclosures and Raceways (2.4.8)
- Emergency Cooling Tower and Reservoir (2.4.9)
- Hazard Barriers and Elastomers (2.4.10)
- Insulation (2.4.11)
- Miscellaneous Steel (2.4.12)
- Nitrogen Storage Building (2.4.13)
- Outdoor Electric Switchgear, North Substation (2.4.14)
- Radwaste Building and Reactor Auxiliary Bay (2.4.15)
- Reactor Building (2.4.16)
- Recombiner Building (2.4.17)
- Stack (2.4.18)
- Station Blackout Structure and Foundations (2.4.19)
- Turbine Building and Main Control Room Complex (2.4.20)
- Watertight Dikes (2.4.21)
- Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (2.4.22)

2.4.1 Administration Building and Shop

Description

The Administration Building and Shop is a multi-story, seismic Class II, nonsafety-related, commercial building located east of the turbine building which houses the administration offices, meeting rooms, shops, equipment, and materials associated with administration and maintenance. The upper floor of the administration building is connected to the operating floor of the turbine building by an enclosed pedestrian bridge. The Administration Building and Shop are supported by steel H bearing piles driven to the rock in the reclaimed and backfilled portion of Conowingo Pond. The superstructure of the administration building consists of a steel framework, and metal deck for the roof. The original administration building is constructed directly over the underground safety-related service water pipe tunnel, and it is therefore determined to be within the scope of license renewal. The pedestrian bridge is located above buried safety-related piping and is therefore determined to be within the scope of license renewal. The building extension was added north of the original administration building, and is not within the scope of license renewal.

Components not necessary for the structural support and structural integrity of the original administration building are not within the scope of license renewal. The finished surfaces and equipment within this commercial building are also not within the scope of license renewal. The service water pipe tunnel is evaluated with Yard Structures.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Administration Building and Shop.

The Administration Building and Shop is further discussed in UFSAR Section 12.2 and Appendix C. The Administration Building and Shop is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Administration Building and Shop is not in scope under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related or relied upon to remain functional during and following design basis events. The Administration Building and Shop meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Administration Building and Shop is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

UFSAR References

12.2.8
12.3.4.5
Appendix C.1.3

Second License Renewal Boundary Drawings

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Table 2.4-1 Administration Building and Shop
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Structural Support
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Structural Support
Concrete: Interior (accessible areas)	Structural Support
Concrete: Interior (inaccessible areas)	Structural Support
Masonry walls: Exterior	Structural Support
Masonry walls: Interior	Structural Support
Piles	Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking	Structural Support

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

Table 3.5.2-1 Administration Building and Shop
Summary of Aging Management Evaluation

2.4.2 Boiler House

Description

The Boiler House, which is also known as the auxiliary boiler building, contains two boilers for plant heating with independent stacks. The Boiler House is a separate building located south of the Unit 2 Reactor Building, and alongside the condensate and refueling water storage tanks. The superstructure consists of a steel frame with pre-cast panel walls, and with roofing on a metal deck. Floor slabs are of cast-in-place concrete with a perimeter edge beam founded on rock. The Boiler House provides support, shelter, and protection for a tank and other components relied upon for fire protection, and the Boiler House stack is over the safety-related Nitrogen Storage Building. The Boiler House is therefore in scope for license renewal.

Components not included in the evaluation boundary of the Boiler House are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), miscellaneous cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, walls, and slabs), and ventilation dampers. Roofing, penetration seals, doors and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, platforms, hatches, and other miscellaneous steel are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The miscellaneous cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Boiler House.

The Boiler House is addressed in UFSAR Section 12.2.13 and in Appendix C as a seismic Category II structure. The Boiler House is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Boiler House is not in scope under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related or relied upon to remain functional during and following design basis events. The Boiler House meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Boiler House also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Boiler House is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

2. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4 (a)(3)

UFSAR References

1.6.5.6
2.7.6.2
12.2.13
Appendix C.1.3

Second License Renewal Boundary Drawings

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Table 2.4-2 <u>Boiler House</u>
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Structural Support
Concrete: Interior (inaccessible areas)	Structural Support
Equipment supports and foundations	Structural Support
Metal components	Shelter and Protection, Structural Support
Precast Concrete- Beams and Panels	Shelter and Protection
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking	Shelter and Protection
Structural Miscellaneous - Siding	Shelter and Protection

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

Table 3.5.2-2 Boiler House
Summary of Aging Management Evaluation

2.4.3 Circulating Water Pump Structure

Description

The Circulating Water Pump Structure is a reinforced concrete structure which consists of several sections founded on rock. The central portion is a reinforced concrete, seismic Class I, tornado-resistant structure. The central portion has three pump bays; one for Unit 2, one for Unit 3, and a third, smaller bay containing the two emergency service water pumps in individual cells. These pump bays are interconnected by openings equipped with sluice gates. The superstructure over these pumps is constructed with reinforced concrete walls and floor and has a concrete roof supported on structural steel beams. Removable panels in the roof provide access to the pumps. A structural steel and plate wall divides the pump area into two rooms for additional protection. The rooms, which are flood protected, are protected by means of watertight doors and sealed floor penetrations. The laydown area concrete slab, supporting foundation piles, and structural steel supports for the crane located to the north of the building are included within the scope of the Circulating Water Pump Structure. Screens are housed in a separate room east of the pump room. Four screens, two per unit, screen the water before it goes into the pump bays. Each screen has a sluice-gated opening on each side. The seismic Class I portion of the circulating water pump structure is designed such that no credible event, including internal flooding due to failure of a seismic Class II structure or component would prevent the equipment housed therein from functioning as necessary to assure safe shutdown of both Units 2 and 3.

Components not included in the evaluation boundary of the Circulating Water Pump Structure are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), the cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, and the fire barrier function of walls and slabs), and ventilation dampers. Roofing is evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, and hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Structures outside of the building such as manholes and retaining walls are evaluated with Yard Structures. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Circulating Water Pump Structure.

The Circulating Water Pump Structure is further discussed in UFSAR Section 12.2.10 and Appendix C. The Circulating Water Pump Structure is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Circulating Water Pump Structure meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Circulating Water Pump Structure meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Circulating Water Pump Structure also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Circulating Water Pump Structure is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4 (a)(1)

2. Provide a source of water for emergency core cooling systems. 10 CFR 54.4 (a)(1)

3. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

4. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4 (a)(3)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4 (a)(3)

UFSAR References

2.4.3.5.7
2.7.6.5.1
10.24.3
12.2.10
Appendix C.1.2
Appendix C.1.3
Appendix C.2.5.4
Appendix F.2.1.4
FPP Figure B-12

Second License Renewal Boundary Drawings

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Table 2.4-3 **<u>Circulating Water Pump Structure</u>**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support, Water Retaining Boundary
Concrete: Below-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Interior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Interior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Equipment supports and foundations	Structural Support
Equipment supports and foundations (Sluice Gate supports and guides)	Structural Support
Equipment supports and foundations (Traveling Water Screen supports)	Structural Support
Hatches/Plugs	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Masonry walls: Interior	Shelter and Protection, Structural Support
Metal components (includes steel plates)	Shelter and Protection, Structural Support
Metal components (sluice gate)	Water Retaining Boundary
Metal components (sluice gate- seat facing)	Water Retaining Boundary
Precast Concrete- Beams and Panels (Precast Panels)	Flood Barrier, Shelter and Protection, Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking	Shelter and Protection, Structural Support

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

Table 3.5.2-3 Circulating Water Pump Structure
Summary of Aging Management Evaluation

2.4.4 Component Supports

Description

The Component Supports commodity group includes the following component groupings: support members, anchors, and grout.

The support members component grouping includes supports for piping and components, HVAC ducts, cables, conduits, cable trays, instrumentation tubing trays, electrical junction and terminal boxes, electrical and I&C devices, instrument tubing, and supports for major equipment, including pumps, heat exchangers, diesel generators, transformers, HVAC fans and filters, and structural items such as masonry walls. This component grouping also includes components such as spring hangers, including the springs, rod hangers, braces, guides, clamps, the paddles at the ends of snubbers, base plates, vibration isolators, metal to metal sliding joints, Lubrite plates, snubber supports, stops, mounting brackets, support bolting, equipment racks, and bottle racks.

The anchors component grouping is the part of the component support assembly used to attach electrical panels, electrical cabinets, racks, switchgears, enclosures for electrical and instrumentation equipment, pipe hangers, pumps, transformers, HVAC fans, and HVAC filters to other components or structures. Welds are used for steel attachments while undercut anchors, expansion anchors, cast-in-place anchors, and grouted-in anchors are used for concrete attachments.

The grout component grouping includes grouted support pads and grouted base plates. Grout is used in the construction of equipment pads, and for filling, leveling, and setting equipment bases to their respective foundations.

Component Supports are treated as a commodity group because of similarities in design, material, aging effect, and or environment. Refer to the “Components Subject to Aging Management Review” table below for a list of components included in the boundary of the Component Supports commodity group.

Component Supports in scope for license renewal are those components in structures and areas with mechanical or electrical components in scope for license renewal. Component Supports are not in scope for license renewal where installed in other structures and areas where there are no mechanical or electrical components in scope for license renewal.

Components not included in the evaluation boundary of the Component Supports commodity group are roof hatches, roof downspout drains, electrical enclosures (conduit, cable trays, cabinets, enclosures, and panels for electrical equipment and instrumentation), dampers, fire rated barriers and enclosures, and fire proofing material. Louvers, roof scuttles, and hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Conduit, cable trays, cabinets, enclosures, and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire protection function of walls and slabs) are evaluated with the Fire Protection System. The Component Supports commodity group includes supports external to components. Supporting members internal to components, such as in the Reactor Vessel, are included within the scope of those mechanical or electrical systems. Structural foundations for building structures are included within the scope of the individual structures. The spent fuel racks are included with the Reactor Building.

Component Supports are included in UFSAR Sections 3.5, 4.2.4, 5.2.3, and Appendix C.5. Component Supports are not shown on the second license renewal boundary drawing since these commodities are included where located in structures in scope for license renewal.

Reason for Scope Determination

The Component Supports meet 10 CFR 54.4(a)(1) because it is a safety-related commodity group that is relied upon to remain functional during and following design basis events. The Component Supports meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the commodity group could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Component Supports also meet 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). The Component Supports are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

3. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

4. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

3.5
4.2.4
5.2.3
Appendix C.5

Second License Renewal Boundary Drawings

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Table 2.4-4 **<u>Component Supports</u>**
Components Subject to Aging Management Review

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

Component Type	Intended Function
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: sliding support bearings; sliding support surfaces	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure (inside manholes)	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: sliding support bearings; sliding support surfaces	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: vibration isolation elements	Structural Support

Component Type	Intended Function
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support

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

Table 3.5.2-4	Component Supports Summary of Aging Management Evaluation

2.4.5 Containment Structure

Description

The Containment Structure consists of the primary containment of each unit and internal structural steel. The primary containment of each unit is of the Mark I design that consists of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and the suppression chamber. The Containment Structure is part of a multi-barrier system with a primary barrier consisting of the primary containment with its pressure suppression system, and a secondary containment consisting of the Reactor Building with a system to limit the ground level release of airborne radioactive material from the secondary containment.

The Containment Structure contains the released steam in the event of the design basis LOCA to limit the release to the Reactor Building of fission products associated with this accident. The Reactor Building encloses the Containment Structure.

The Containment Structure is an enclosure for the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor coolant system. It includes a drywell and connected pressure suppression chamber, isolation valves, vacuum breakers, containment cooling systems, and other service equipment. The drywell is a steel pressure vessel in the shape of a light bulb, and the pressure suppression chamber is a torus-shaped steel pressure vessel located below and encircling the drywell. The primary containment is a seismic Class I structure. The drywell is enclosed in reinforced concrete for shielding purposes.

The stiffened pressure suppression chamber is a steel pressure vessel in the shape of a torus. It contains approximately 125,000 cubic feet of water and has a gas space volume above the pool. The suppression chamber is supported on braced vertical columns to carry its loading to the reinforced concrete foundation slab of the Reactor Building.

Internal structural steel is provided at various elevations of the primary containment drywell and the pressure suppression chamber. The internal structural steel provides structural support to safety-related and nonsafety-related systems and equipment inside the primary containment drywell. It also provides personnel access to the equipment for maintenance and testing.

Internal reinforced concrete structures inside of the drywell, such as the drywell floor, reactor pedestal, and the sacrificial shield wall around the reactor vessel, are evaluated with the Containment Structure.

Moisture barriers, penetration assemblies, and sleeves associated with the drywell and torus containment boundary are evaluated with the Containment Structure.

Components not included in the evaluation boundary of the Containment Structure are component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), cranes, lead shielding blankets, miscellaneous steel, containment isolation valves, and Reactor Building components around the outside of the Containment Structure. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The cranes are evaluated with the Cranes and Hoists System. Hazard Barriers and Elastomers include permanent lead shielding blankets. Miscellaneous structural components such as grating, handrails, ladders, platforms, and toe boards are evaluated with the Miscellaneous Steel commodity group. The containment isolation valves are evaluated in the evaluation boundary of the Primary Containment Isolation System. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Containment Structure are evaluated with their respective mechanical and electrical license renewal systems or commodities group. The reinforced concrete structures that enclose the drywell for shielding purposes, such as the drywell shield wall and shield plugs at the top of the reactor well, are evaluated with the Reactor Building.

The Containment Structure is discussed in UFSAR Sections 5.2, 14.6, and Appendix M.3. The Containment Structure is inside the Reactor Building shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Containment Structure meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Containment Structure meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Containment Structure also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide primary containment boundary. 10 CFR 54.4(a)(1)

3. Controls the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)

4. Controls the release of fission products to the secondary containment in the event of a design basis loss-of-coolant accident (LOCA) so that offsite consequences are within acceptable limits. 10 CFR 54.4(a)(1)

5. Provides sufficient air and water volumes to absorb the energy released to the containment in the event of design basis events so that the pressure is within acceptable limits. 10 CFR 54.4(a)(1)

6. Provides a source of water for emergency core cooling systems. 10 CFR 54.4(a)(1)

7. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components (SSCs) whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

8. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulation for Fire Protection (10 CFR 50.48).
10 CFR 54.4(a)(3)

9. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulation for Environmental Qualification (10 CFR 50.49).
10 CFR 54.4(a)(3)

10. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulation for Anticipated Transients Without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)

11. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulation for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

5.2
14.6
Appendix C.2.6
Appendix C.4
Appendix M

Second License Renewal Boundary Drawings

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Table 2.4-5 Containment Structure
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Containment Closure)	Structural Pressure Barrier
	Structural Support
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Interior (accessible areas-drywell floor and reactor pedestal)	Structural Support
Concrete: Interior (inaccessible areas-drywell floor and reactor pedestal)	Structural Support
Concrete: near reactor vessel (sacrificial shield wall)	Direct Flow, Structural Support
	HELB/MELB Shielding
	Shielding
Doors (in sacrificial shield wall)	HELB/MELB Shielding
	Shielding, Structural Support
Hazard Barrier (penetrations through the sacrificial shield wall)	Shielding
	Structural Support
Penetration - Containment Electrical	Shelter and Protection, Structural Pressure Barrier, Structural Support
Penetration - Containment Mechanical	Shelter and Protection, Structural Pressure Barrier, Structural Support
Penetration - Containment Mechanical (flued heads and bellows)	Expansion/Separation
	Shelter and Protection, Structural Pressure Barrier, Structural Support
Penetration - Containment Sleeves	Shelter and Protection, Structural Pressure Barrier, Structural Support
Penetration - Containment- spares, access manholes, inspection ports	Shelter and Protection, Structural Pressure Barrier, Structural Support
Personnel airlock, CRD hatch, equipment hatch	Shelter and Protection, Structural Pressure Barrier, Structural Support
Personnel airlock, CRD hatch, equipment hatch (locks, hinges, closure mechanisms)	Structural Pressure Barrier
	Structural Support
Pipe Whip Restraints and Jet Impingement Shields	Direct Flow, Structural Support
	HELB/MELB Shielding
	Pipe Whip Restraint
Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	Shelter and Protection
Service Level I Coating	Maintain Adhesion
Sliding surfaces	Structural Support

Component Type	Intended Function
Steel components: sacrificial shield wall and stabilizer	Structural Support
Steel components: sacrificial shield wall and stabilizer (vent ducts)	Direct Flow
Steel components: structural steel	Structural Support
Steel components: structural steel (seal plate)	Structural Support
	Water Retaining Boundary
Steel elements: Downcomers	Direct Flow, Structural Pressure Barrier, Structural Support
Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	Shelter and Protection, Structural Pressure Barrier, Structural Support
Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	Shelter and Protection, Structural Pressure Barrier, Structural Support
Steel elements: Drywell - support skirt (inaccessible areas)	Structural Support
Steel elements: Liner, liner anchors, integral attachments - accessible areas (reactor pedestal and sacrificial shield wall)	Structural Support
Steel elements: Liner, liner anchors, integral attachments - inaccessible areas (reactor pedestal and sacrificial shield wall)	Structural Support
Steel elements: Refueling Bellows assemblies	Water Retaining Boundary
Steel elements: Torus - shell	Structural Pressure Barrier, Structural Support, Water Retaining Boundary
Steel elements: Torus - shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary
Steel elements: Vent line, header, and bellows (accessible areas)	Direct Flow, Structural Pressure Barrier, Structural Support
	Expansion/Separation
	Structural Pressure Barrier
Steel elements: Vent line, header, and bellows (inaccessible areas)	Direct Flow, Structural Pressure Barrier, Structural Support
	Expansion/Separation
	Structural Pressure Barrier

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

Table 3.5.2-5 Containment Structure
Summary of Aging Management Evaluation

2.4.6 Dewatering Building

Description

The Dewatering Building (resin dewatering facility) is located west of the Unit 2 Reactor Building. The Dewatering Building houses nonsafety-related liquid radwaste processing equipment. The two-bay single story structure is constructed of reinforced masonry block walls over a 1 foot concrete curb. The roof of the building is supported by metal decking over commercial, prefabricated, roof trusses. The building is not classified as seismic Class I structure in UFSAR Appendix C.1.2. This building is directly over and supported by the safety-related Reactor Building slab, and also directly above the safety-related primary containment torus. It is therefore considered in scope for license renewal.

Components not necessary for the structural support and structural integrity of the Dewatering Building are not within the scope of license renewal. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Dewatering Building.

The Dewatering Building is not discussed in the UFSAR. The Dewatering Building is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Dewatering Building is not in scope under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related or relied upon to remain functional during and following design basis events. The Dewatering Building meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Dewatering Building is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

UFSAR References

None

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Table 2.4-6 Dewatering Building
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Structural Support
Masonry walls: Exterior	Structural Support
Masonry walls: Interior	Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking	Structural Support

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

Table 3.5.2-6 Dewatering Building
Summary of Aging Management Evaluation

2.4.7 Diesel Generator Building

Description

The Diesel Generator Building is a seismic Class I structure. The Diesel Generator Building is a separate structure located south of the Unit 2 turbine building. The building is founded on steel H piles and concrete shear walls which are supported on rock. The superstructure of the building consists of reinforced concrete walls and roof. Large openings in the Diesel Generator Building are either protected by missile-proof doors, or have baffle walls located in front of them. The emergency diesel fuel supply is stored in underground steel tanks east of the building.

Components not included in the evaluation boundary of the Diesel Generator Building are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), the cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, and the fire barrier function of walls and slabs), and ventilation dampers. Roofing is evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, and hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire barrier function of walls and slabs) are evaluated with the Fire Protection System. The underground tanks are evaluated with the Emergency Diesel Generator system. Structures outside of the building such as manholes and retaining walls are evaluated with Yard Structures. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Diesel Generator Building.

The Diesel Generator Building is further discussed in UFSAR Section 12.2 and Appendix C. The Diesel Generator Building boundaries are the exterior of the structure and are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Diesel Generator Building meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Diesel Generator Building meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Diesel Generator Building also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Diesel Generator Building is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

3. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

4. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

12.2.5
Appendix C
FPP

Second License Renewal Boundary Drawings

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Table 2.4-7 Diesel Generator Building
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier, Shelter and Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Equipment supports and foundations	Structural Support
Metal components	Shelter and Protection
	Structural Support
Piles	Structural Support
Steel components: structural steel	Missile Barrier
	Structural Support
Structural Miscellaneous- Decking	Structural Support

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

Table 3.5.2-7 Diesel Generator Building
Summary of Aging Management Evaluation

2.4.8 Electrical and Instrumentation Enclosures and Raceways

Description

The Electrical and Instrumentation Enclosures and Raceways commodity group includes commodity groupings consisting of enclosures, for electrical and instrumentation equipment, and raceways. The electrical and instrumentation enclosures include components such as electrical panels, frames and racks, cabinets, and boxes, and enclosures that contain sample stations. The raceways include components such as cable trays, cable tray covers, rigid and flexible electrical conduits and fittings, wireway gutters, and instrument tubing tray. These components are treated as a commodity group because of similarities in design, material, and environment. Refer to the “Components Subject to Aging Management Review” table below for a list of components included in the boundary of the Electrical and Instrumentation Enclosures and Raceways commodity group.

Electrical and Instrumentation Enclosures and Raceways in scope for license renewal are those components in structures and areas with mechanical or electrical components in scope for license renewal. Electrical and Instrumentation Enclosures and Raceways are not in scope for license renewal where installed in other structures and areas where there are no mechanical or electrical components in scope for license renewal.

Components not included in the evaluation boundary of the Electrical and Instrumentation Enclosures and Raceways commodity group are component supports, cranes, fire rated barriers and enclosures, and fire proofing material. Component supports are evaluated in the Component Supports commodity group. The cranes are evaluated with the Cranes and Hoists System. The fire barrier functions of components such as fire rated doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire protection function of walls and slabs are evaluated with the Fire Protection System. In addition, the mechanical and electrical systems and components housed in or located within Electrical and Instrumentation Enclosures and Raceways are evaluated with their respective mechanical and electrical license renewal systems or commodities group.

Electrical and Instrumentation Enclosures and Raceways are included in UFSAR Section 8.4.5 and Appendix C.5.3.5. Electrical and Instrumentation Enclosures and Raceways are not shown on the second license renewal boundary drawing since these commodities are included where located in structures in scope for license renewal.

Reason for Scope Determination

The Electrical and Instrumentation Enclosures and Raceways commodity group meets 10 CFR 54.4(a)(1) because the commodity group includes safety-related components that are relied upon to remain functional during and following design basis events. The Electrical and Instrumentation Enclosures and Raceways commodity group meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the commodity group could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Electrical and Instrumentation Enclosures and Raceways commodity group also meets 10 CFR 54.4(a)(3) because the commodity group is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

3. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

4. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

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

6. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

7.1.6
7.3.4.9
8.4.5
Appendix A.10
Appendix C.5.3.5

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Table 2.4-8 Electrical and Instrumentation Enclosures and Raceways Components Subject to Aging Management Review

Component Type	Intended Function
Conduit	Shelter and Protection, Structural Support
Metal components (cable tray and wireway gutter)	Shelter and Protection, Structural Support
Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter and Protection, Structural Support
Panels, Racks, Frames, Cabinets, and Other Enclosures (Boxes)	Shelter and Protection, Structural Support
Tube Track	Shelter and Protection, Structural Support
Windows (in panels)	Shelter and Protection

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

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways Summary of Aging Management Evaluation

2.4.9 Emergency Cooling Tower and Reservoir

Description

The Emergency Cooling Tower and Reservoir and associated mechanical and electrical equipment are classified as seismic Class I. The Class I elements of the emergency cooling tower and reservoir structure are founded on rock.

The reservoir of the emergency cooling tower has a one-week water storage capacity, and is a reinforced concrete tank structure approximately 25 feet deep with a pre-cast, prestressed concrete roof. The tank structure is founded on rock.

The emergency cooling tower is a mechanical induced draft type, consisting of three cells. The reservoir and tower facility is a reinforced concrete structure. The emergency cooling tower fill consists of vitreous clay tiles of the multi-cell block design. Refer to the “Components Subject to Aging Management Review” table below for a complete list of components included in the boundary of the Emergency Cooling Tower and Reservoir.

Components not included in the evaluation boundary of the Emergency Cooling Tower and Reservoir are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), miscellaneous cranes, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, and the fire barrier function of walls and slabs), and ventilation dampers. Roofing is evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, roof scuttles, and metal roof hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The miscellaneous cranes are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire barrier function of walls and slabs) are evaluated with the Fire Protection System. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Emergency Cooling Tower and Reservoir are evaluated with their respective mechanical and electrical license renewal systems or commodities group.

The Emergency Cooling Tower and Reservoir is discussed in UFSAR Sections 10.24, 12.2.15, and Appendix C. The Emergency Cooling Tower and Reservoir is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Emergency Cooling Tower and Reservoir meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Emergency Cooling Tower and Reservoir meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the system could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Emergency Cooling Tower and Reservoir also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Emergency Cooling Tower and Reservoir is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide Ultimate Heat Sink (UHS) during design basis events. 10 CFR 54.4(a)(1)

3. Provide a source of cooling water for plant safe shutdown. 10 CFR 54.4(a)(1)

4. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

UFSAR References

2.4.3.5.7
2.7.6.4
10.24
12.2.15
Appendix C

Second License Renewal Boundary Drawings

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Table 2.4-9 Emergency Cooling Tower and Reservoir
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Below-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support, Water Retaining Boundary
Concrete: Interior (accessible areas)	Structural Support
	Water Retaining Boundary
Concrete: Interior (inaccessible areas)	Structural Support
	Water Retaining Boundary
Cooling tower: Drift Eliminator	Direct Flow, Structural Support
Cooling tower: Fill	Heat Transfer
	Structural Support
Hatches/Plugs	Shelter and Protection
Masonry walls: Interior	Shelter and Protection, Structural Support
	Structural Support
Metal components	Structural Support
Metal components (fill support)	Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking (roof)	Structural Support

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

Table 3.5.2-9 Emergency Cooling Tower and Reservoir
Summary of Aging Management Evaluation

2.4.10 Hazard Barriers and Elastomers

Description

Hazard Barriers and Elastomers commodity group includes those hazard barriers not associated with a fire protection function or the overall structure, such as a floor or wall. Hazard barriers include penetration seals, penetration sleeves, hazard barrier doors, and other hazard barriers such as missile, radiation, and spray shields. Elastomer components include expansion joint seals (seismic joint seal material, control joint seal material, and seismic separation joint seal material), gaskets at hatches and doors, spent fuel pool gate seals, blowout panel seals, and metal siding gap seals. Hazard Barriers and Elastomers also includes roofing assemblies, permanent lead shielding blankets, and penetration sleeves, except for sleeves associated with the drywell and torus containment boundary. Hazard Barriers and Elastomers are treated as a commodity because of similarities in design, material, aging effect, and or environment.

Hazard Barriers and Elastomers in scope for license renewal are those components in structures and areas with mechanical or electrical components in scope for license renewal. Hazard Barriers and Elastomers are not in scope for license renewal where installed in other structures and areas where there are no mechanical or electrical components in scope for license renewal.

Components not included in the evaluation boundary of the Hazard Barriers and Elastomers are roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), dampers, fire rated barriers and enclosures, fire proofing material, fire protection function of walls and slabs, and ventilation dampers, sleeves associated with the drywell and torus containment boundary. Louvers, roof scuttles, and hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire protection function of walls and slabs) are evaluated with the Fire Protection System. Building structure components, such as walls and floors that provide a hazard barrier function, are evaluated with the individual structures. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. Moisture barriers, penetrations, and sleeves associated with the drywell and torus containment boundary are evaluated with the Containment Boundary structure.

Hazard Barriers and Elastomers are included in UFSAR Sections 12.2 and 12.3. Hazard Barriers and Elastomers are not shown on the second license renewal boundary drawing since these commodities are included where located in structures in scope for license renewal.

Reason for Scope Determination

The Hazard Barriers and Elastomers meet 10 CFR 54.4(a)(1) because some of these structural components are safety-related commodities that are relied upon to remain functional during and following design basis events. The Hazard Barriers and Elastomers meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of this structural commodity group could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Hazard Barriers and Elastomers also meet 10 CFR 54.4(a)(3) because some of these structural components are relied upon in the safety analyses and 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), and Station Blackout (10 CFR 50.63). The Hazard Barriers and Elastomers are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4 (a)(1)

2. Control the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)

3. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

4. Provides structural support or restraint to SSCs in the scope of license renewal. 10 CFR 54.4(a)(2)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4 (a)(3)

6. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4 (a)(3)

7. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4 (a)(3)

8. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4 (a)(3)

UFSAR References

2.4
5.3
12.2
12.3
Appendix C.2.4
Appendix C.2.5.4
FPP 3.2
FPP 3.3
FPP 6.3

Second License Renewal Boundary Drawings

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Table 2.4-10 **<u>Hazard Barriers and Elastomers</u>**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Door Seal	Flood Barrier
	HELB/MELB Shielding
	Shelter and Protection, Structural Pressure Barrier
Doors	Flood Barrier
	HELB/MELB Shielding
	Missile Barrier
	Shelter and Protection, Structural Pressure Barrier
	Shielding
Expansion Joints	Expansion/Separation
Hazard Barrier	HELB/MELB Shielding
	Missile Barrier
	Shelter and Protection
	Shielding
	Shielding, Structural Support
Hazard Barrier (permanent lead shielding blankets)	Structural Support
Penetration Seals	Flood Barrier, Shelter and Protection, Structural Support
	HELB/MELB Shielding
	Shielding
	Structural Pressure Barrier
	Water Retaining Boundary
Penetration sleeves	Flood Barrier, Shelter and Protection, Structural Support
	HELB/MELB Shielding
	Shielding
	Structural Pressure Barrier
Roofing	Shelter and Protection, Structural Pressure Barrier
Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	Flood Barrier
	Shelter and Protection
	Shelter and Protection, Structural Pressure Barrier
Seals, gaskets, and moisture barriers (spent fuel pool gates)	Water Retaining Boundary

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

Table 3.5.2-10 Hazard Barriers and Elastomers
Summary of Aging Management Evaluation

2.4.11 Insulation

Description

Thermal insulation and jacketing that are installed on piping and other mechanical components within the scope of license renewal are also within the scope of license renewal. Metallic insulation consists of stainless steel mirror insulation. Nonmetallic insulation materials consist of calcium silicate, mineral or glass fiber, cellular glass, fiberglass cloth blankets, insulating cement, silicone and plastic foam caulking, and adhesives. Insulation jacketing consists of aluminum or stainless steel sheet panels held in place by metallic straps, clips, or screws. Mastic-plastic compound, silicone impregnated fiberglass, or fiberglass jacketing with stainless steel stitching is also used for some applications.

Insulation, on piping and components located inside structures that contain safety-related components, functions to assist ventilation systems in maintaining area temperatures within design limits to maintain environmental qualification, and to protect nearby safety-related components from localized overheating. Insulation is designed and installed to prevent the intrusion of moisture, which if allowed to accumulate under the insulation, could result in accelerated corrosion of the insulated component. Thermal insulation also provides personnel protection, improves thermal efficiency of plant systems, provides freeze protection for outdoor heat traced piping, and prevents sweating on piping that is normally at temperatures below the ambient dew point.

Insulation is included in UFSAR Sections 4.2, 4.3, 5.2, and 10.4. Insulation is not shown on the second license renewal boundary drawings since insulation is included where located on piping and other mechanical components in scope for license renewal.

Reason for Scope Determination

Insulation is not in scope under 10 CFR 54.4(a)(1) because no portions of the system are safety-related or relied upon to remain functional during and following design basis events. Insulation is in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related Insulation could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). Insulation is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Nonsafety-related thermal insulation on piping components prevents excessive localized and general area temperatures from causing failure of safety-related SSCs. Thermal insulation systems are designed to prevent the intrusion of moisture, which if allowed to accumulate under the insulation, could result in accelerated corrosion of the insulated safety-related component. 10 CFR 54.4 (a)(2)

UFSAR References

4.2.4.9
4.2.6
4.3.4
5.2.3.4.2
10.4.4
Appendix K
FPP

Second License Renewal Boundary Drawings

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Table 2.4-11 Insulation
Components Subject to Aging Management Review

Component Type	Intended Function
Insulation Jacketing- Thermal	Thermal Insulation Jacket Integrity
Insulation- Thermal	Thermal Insulation

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

Table 3.5.2-11 Insulation
Summary of Aging Management Evaluation

2.4.12 Miscellaneous Steel

Description

The Miscellaneous Steel commodity group includes platforms, grating, stairs, ladders, steel curbs, handrails, kick plates, diamond plate type decking, hatches, and manhole covers. This commodity group also includes vents, louvers, and roof scuttles. These steel and other metal components are generally installed throughout PBAPS structures. Some components are exposed to the outdoor environment. The Miscellaneous Steel components are treated as a commodity group because of similarities in design, material and/or environment.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of Miscellaneous Steel. Miscellaneous Steel is not described in the UFSAR. Miscellaneous Steel is not shown on the second license renewal boundary drawing since these commodities are included where located in structures which are in scope for license renewal.

Reason for Scope Determination

The Miscellaneous Steel meets 10 CFR 54.4(a)(1) because some of these components are safety-related commodities that are relied upon to remain functional during and following design basis events. The Miscellaneous Steel meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of these structural components could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Miscellaneous Steel also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Miscellaneous Steel is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

3. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

4. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

None

Second License Renewal Boundary Drawings

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Table 2.4-12 Miscellaneous Steel
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Metal components	Direct Flow, Shelter and Protection
Structural Miscellaneous - Decking	Shelter and Protection, Structural Support
Structural Miscellaneous - Vents	Direct Flow, Shelter and Protection
Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc	Shelter and Protection, Structural Support

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

Table 3.5.2-12 Miscellaneous Steel
Summary of Aging Management Evaluation

2.4.13 Nitrogen Storage Building

Description

The Nitrogen Storage Building, which is also known as the Post-LOCA CADS liquid N2 tank building in the UFSAR, is a safety-related seismic Class I reinforced concrete structure founded on rock, and located south of the Unit 2 Reactor Building. The western portion of the building is supported and connected to the residual heat removal pump room cover slab. The east wall is next to the Unit 2 condensate storage water dike wall. The north wall is structurally separated from the Reactor Building to eliminate interaction between both structures.

Components not included in the evaluation boundary of the Nitrogen Storage Building are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), miscellaneous cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, walls, and slabs), and ventilation dampers. Roofing, penetration seals, doors and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, platforms, hatches, and other miscellaneous steel are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The miscellaneous cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Nitrogen Storage Building.

The Nitrogen Storage Building (Post-LOCA CADS liquid N2 tank building) is addressed in UFSAR Appendix C as a seismic Category I structure. The Nitrogen Storage Building is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Nitrogen Storage Building meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Nitrogen Storage Building is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Nitrogen Storage Building also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Nitrogen Storage Building is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4 (a)(1)

2. Provide structural support or restraint to SSCs not in the scope of license renewal to prevent interaction with safety-related SSCs. 10 CFR 54.4 (a)(2)

3. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4 (a)(3)

UFSAR References

5.2.3.9.3
Appendix C.1.2

Second License Renewal Boundary Drawings

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Table 2.4-13 Nitrogen Storage Building
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Interior (inaccessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Equipment supports and foundations	Structural Support

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

Table 3.5.2-13 Nitrogen Storage Building
Summary of Aging Management Evaluation

2.4.14 Outdoor Electric Switchgear, North Substation

Description

The Outdoor Electric Switchgear, North Substation scoping evaluation includes the structures and control buildings in both the north and south substations, towers and poles for the conductors between the powerblock and the substations, the onsite outdoor switchgear buildings west of the plant services building and northwest of the diesel generator building, as well as outdoor transformer foundations.

The electrical scoping evaluations in the electrical systems, such as 4 kV System, 13 kV System, Substations and Transformers, and Station Blackout System, define the electrical systems and components in scope for license renewal. The structural components that support this electrical equipment, which are in scope for license renewal, define the structures and components, within the boundary of the Outdoor Electric Switchgear, North Substation, that are in scope for license renewal.

The north substation control houses, towers, poles, ductbanks and raceways for the conductors between the powerblock and the substation, and associated structures and foundations at the substation necessary for SBO and Fire Safe Shutdown are in scope for license renewal. The onsite Unit 2 startup switchgear building and associated breaker and transformer foundations northwest of the Diesel Generator Building are determined in scope for license renewal. The Unit 3 startup switchgear building and the nearby 343 switchgear building west of the plant services building are both in scope for license renewal. The onsite emergency auxiliary transformer foundations located west of the powerblock are in scope for license renewal. Ductbanks and electrical raceway connecting these structures and equipment together and to the powerblock are included in scope for license renewal.

Components not included in the evaluation boundary for aging management of the Outdoor Electric Switchgear, North Substation are doors and elastomeric seals, and electrical equipment and cables, as well as the onsite SBO substation and SBO switchgear building, and the associated cable trenches and the buried ductbanks and SBO electric manholes. Components also not included in the evaluation boundary of the Outdoor Electric Switchgear, North Substation are component supports other than the towers, poles and foundations addressed here, electrical enclosures (cabinets, enclosures, and panels for electrical equipment and instrumentation), doors, penetration seals and sleeves, and firewalls. Penetration seals, doors and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, platforms, manhole covers, hatches, and other miscellaneous steel are evaluated with the Miscellaneous Steel commodity group. Conduit, cable trays, cabinets, enclosures, and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Fire barriers including firewalls at transformers are evaluated with the Fire Protection System. Component supports other than the foundations, towers, poles, and substation supports mentioned above are evaluated with the Component Supports commodity group. The onsite SBO substation and SBO manhole are included and evaluated with the Station Blackout Structure and Foundations scoping package. Other cable trenches, buried ductbanks and electric manholes at the station, which are not relied upon for SBO, are evaluated with Yard Structures. Mechanical and electrical systems and components housed or associated with these structures are separately evaluated with their respective mechanical systems, electrical systems, or commodity groups.

Refer to the "Components Subject to Aging Management Review" table below for a list of component types included in the boundary of the Outdoor Electric Switchgear, North Substation.

The Outdoor Electric Switchgear, North Substation components are further discussed in UFSAR Sections 8.1, 8.4, and Appendix C. The Outdoor Electric Switchgear, North Substation are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Outdoor Electric Switchgear, North Substation is not in scope under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related or relied upon to remain functional during and following design basis events. The Outdoor Electric Switchgear, North Substation is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Outdoor Electric Switchgear, North Substation meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Outdoor Electric Switchgear, North Substation is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48).
10 CFR 54.4(a)(3)

2. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63).
10 CFR 54.4(a)(3)

UFSAR References

8.1
8.3.2
8.4.6.1
8.4.6.2
Appendix C.1.3

Second License Renewal Boundary Drawings

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Table 2.4-14 Outdoor Electric Switchgear, North Substation Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation	Structural Support
Concrete: Interior	Structural Support
Manholes, Handholes & Duct Banks	Shelter and Protection, Structural Support
Metal components (includes poles and outdoor structures)	Structural Support
Roofing	Shelter and Protection
Steel components: structural steel	Structural Support
Structural Miscellaneous - Siding	Shelter and Protection

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

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation Summary of Aging Management Evaluation

2.4.15 Radwaste Building and Reactor Auxiliary Bay

Description

The Radwaste Building and Reactor Auxiliary Bay is adjacent to the main control room complex and is located between the two Reactor Buildings. The Radwaste Building and Reactor Auxiliary Bay is a seismic Class I structure. The radwaste building houses various components of the Radwaste System, the Standby Gas Treatment System, and associated equipment. The Radwaste Building and Reactor Auxiliary Bay also houses the recirculation system motor generator sets, which are no longer used for the station, along with the heating and ventilating equipment for the radwaste building and the main control room. There are two adjoining reactor auxiliary bays, one for each unit, which house HPCI and RCIC turbine pumps, and RHR equipment.

The Radwaste Building and Reactor Auxiliary Bay is founded on rock with a reinforced concrete mat. All walls except the west wall are concrete up to the roof. The west wall consists of concrete and metal siding for its full height.

The HPCI and RCIC equipment is protected by concrete walls and floor slabs for protection from floods, missiles, and tornados.

The heating and ventilating equipment located in the HVAC equipment rooms is considered essential for a safe shutdown of the plant, and thus is protected from tornado missiles.

Components not included in the evaluation boundary of the Radwaste Building and Reactor Auxiliary Bay are roofing, doors, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), cranes, hazard barriers such as penetration seals and sleeves, and ventilation dampers. Roofing and doors, as well as penetration seals and sleeves, are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, roof scuttles, and metal hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The cranes are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Radwaste Building and Reactor Auxiliary Bay are evaluated with their respective mechanical and electrical license renewal systems or commodities group.

The Radwaste Building and Reactor Auxiliary Bay is discussed in UFSAR Section 12.2.4 and Appendix C. The Radwaste Building and Reactor Auxiliary Bay are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Radwaste Building and Reactor Auxiliary Bay meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Radwaste Building and Reactor Auxiliary Bay meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Radwaste Building and Reactor Auxiliary Bay also meets 10 CFR 54.4(a)(3) because the structure is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Control the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)

3. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

4. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

6. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)

7. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

12.2.4
Appendix C.1

Second License Renewal Boundary Drawings

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Table 2.4-15 **Radwaste Building and Reactor Auxiliary Bay**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier, Shelter and Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Flood Barrier, HELB/MELB Shielding, Missile Barrier, Shelter and Protection, Shielding, Structural Support
Concrete: Interior (inaccessible areas)	Flood Barrier, HELB/MELB Shielding, Missile Barrier, Shelter and Protection, Shielding, Structural Support
Doors (special shield doors)	Missile Barrier
	Shelter and Protection
	Shielding
Equipment supports and foundations	Structural Support
Hatches/Plugs	HELB/MELB Shielding
	Shelter and Protection, Structural Support
Masonry walls: Interior	Shielding
	Structural Support
Metal components	Shelter and Protection, Structural Support
Metal components (missile shield)	Missile Barrier
Precast Concrete- Beams and Panels	Flood Barrier
	Shelter and Protection, Structural Support
Sliding surfaces	Expansion/Separation
Steel components: structural steel	Flood Barrier
	Structural Support
Structural Miscellaneous - Decking (floor)	Structural Support
Structural Miscellaneous - Decking (roof)	Structural Support
Structural Miscellaneous - Shielding	Shielding, Structural Support
Structural Miscellaneous - Siding	Shelter and Protection

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

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay
Summary of Aging Management Evaluation

2.4.16 Reactor Building

Description

The Reactor Building, for each unit, is a seismic Class I structure completely enclosing the primary containment and auxiliary systems of the nuclear steam supply system, and housing the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The building is a reinforced concrete structure from its foundation floor to its refueling floor. Above this floor, the building superstructure consists of metal siding and roof decking supported on structural steel framework. The foundation of the building consists of a reinforced concrete mat supported on rock. This mat also supports the primary containment and its internals, including the reactor vessel pedestal. The exterior and some interior walls of the building above the foundation are cast-in-place concrete. Other interior walls are normal weight concrete block walls. Floor slabs of the buildings are of composite construction with cast-in-place concrete over structural steel beams and metal floor deck. The thickness of walls and slabs were governed by structural requirements or shielding requirements.

The steel-framed superstructure is cross-braced to withstand wind and earthquake forces, supports metal siding, metal roof deck, and roofing. The frame also supports a runway for the reactor building crane. Refer to the “Components Subject to Aging Management Review” table below for a list of components included in the boundary of the Reactor Building.

Components not included in the evaluation boundary of the Reactor Building are roofing, doors, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), the reactor building crane, other miscellaneous cranes, hazard barriers such as penetration seals and sleeves, and ventilation dampers. Roofing and doors, as well as penetration seals and sleeves, are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, roof scuttles, and metal hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The reactor building cranes and other miscellaneous cranes are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, walls, and slabs) are evaluated with the Fire Protection System. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. The Secondary Containment license renewal system includes the following portion of the reactor building HVAC system: the valves which isolate secondary containment, along with the associated ductwork and controls. The Secondary Containment System interfaces with the Standby Gas Treatment System, which is evaluated separately. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Reactor Building are evaluated with their respective mechanical and electrical license renewal systems or commodities group.

The Reactor Building is discussed in UFSAR Section 12.2.1 and Appendix C. The Reactor Building is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Reactor Building meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Reactor Building meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Reactor Building also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4(a)(2)

3. Provide protection for safe storage of new and spent fuel. 10 CFR 54.4(a)(1)

4. Control the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)

5. Provide for the discharge of treated gaseous waste to meet the requirements of 10 CFR 50.67 or 10 CFR 100. 10 CFR 54.4(a)(1)

6. Prevent liquid radioactive waste from being released to the environment in the event of a Safe Shutdown Earthquake (SSE). 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

7. Prevent criticality of fuel assemblies stored in the spent fuel pool. 10 CFR 54.4(a)(1)

8. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

9. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

10. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)

11. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63).
10 CFR 54.4(a)(3)

UFSAR References

2.4.3.5
2.7.6.3
2.7.6.4
5.1.3
5.3.1
7.12.5
10.2
10.3
10.4.9
10.5
12.2.1
Appendix C
FPP 5.3.41

Second License Renewal Boundary Drawings

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Table 2.4-16 **Reactor Building**
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier, Shelter and Protection, Structural Pressure Barrier, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Pressure Barrier, Structural Support
Concrete: Interior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
	HELB/MELB Shielding
Concrete: Interior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
	HELB/MELB Shielding
Equipment Storage Racks (inside spent fuel pool and reactor well)	Structural Support
Equipment supports and foundations	Structural Support
Fuel Storage Racks (New Fuel)	Structural Support
Fuel Storage Racks (Spent Fuel)	Structural Support
Fuel Storage Racks: neutron absorbing sheets	Absorb Neutrons
Hatches/Plugs	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Hatches/Plugs (reactor well)	Shielding
	Water Retaining Boundary
Masonry walls: Interior	HELB/MELB Shielding
	Shelter and Protection, Structural Support
	Shielding
Metal components	Direct Flow
	Shelter and Protection
	Structural Support
Pipe Whip Restraints and Jet Impingement Shields	HELB/MELB Shielding

Component Type	Intended Function
Pipe Whip Restraints and Jet Impingement Shields	Pipe Whip Restraint
	Structural Support
Spent fuel pool gates	Water Retaining Boundary
Steel components: structural steel	Missile Barrier
	Structural Support
Steel elements: Liner, liner anchors, integral attachments - accessible areas	Structural Support
	Water Retaining Boundary
Steel elements: Liner, liner anchors, integral attachments - inaccessible areas	Structural Support
	Water Retaining Boundary
Structural Miscellaneous - Decking (floor)	Structural Support
Structural Miscellaneous - Decking (roof)	Structural Pressure Barrier
	Structural Support
Structural Miscellaneous - Shielding	Shielding
	Structural Support
Structural Miscellaneous - Siding	Shelter and Protection, Structural Pressure Barrier
Structural Miscellaneous - Vents (blowout panels)	Pressure Relief, Shelter and Protection, Structural Pressure Barrier

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

Table 3.5.2-16 Reactor Building
Summary of Aging Management Evaluation

2.4.17 Recombiner Building

Description

The Recombiner Building is a seismic Class I, rectangular, reinforced concrete structure founded on rock. The Recombiner Building houses the hydrogen recombiner system catalytic recombiner, condensers, preheaters, analyzers, and other system equipment. This structure is located north of the Unit 3 Reactor Building and west of the Unit 3 turbine building. The Recombiner Building is a shared structure and houses equipment for both Unit 2 and Unit 3. Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Recombiner Building.

Components not included in the evaluation boundary of the Recombiner Building are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), the cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, and the fire barrier function of walls and slabs), and ventilation dampers. Roofing and doors are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, and hatches are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

The Recombiner Building is discussed in UFSAR Section 12.1 and Appendix C. The Recombiner Building is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Recombiner Building is not in scope under 10 CFR 54.4(a)(1) because no portions of the structure are safety-related and relied upon to remain functional during and following design basis events. The Recombiner Building meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Recombiner Building also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Recombiner Building is not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

2. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

UFSAR References

12.1
Appendix C.1

Second License Renewal Boundary Drawings

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Table 2.4-17 Recombiner Building
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Shelter and Protection, Structural Support
Concrete: Interior (inaccessible areas)	Shelter and Protection, Structural Support
Equipment supports and foundations	Structural Support
Hatches/Plugs	Shelter and Protection, Structural Support
Masonry walls: Exterior	Shelter and Protection, Structural Support
Masonry walls: Interior	Shelter and Protection, Structural Support
Metal components	Structural Support
Precast Concrete- Beams and Panels	Shelter and Protection, Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking (roof)	Shelter and Protection, Structural Support
Structural Miscellaneous - Siding	Shelter and Protection, Structural Support
Structural Miscellaneous - Vents (blowout panel)	Pressure Relief, Shelter and Protection

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

Table 3.5.2-17 Recombiner Building
Summary of Aging Management Evaluation

2.4.18 Stack

Description

A single stack is used to discharge gaseous waste from both units. The Stack license renewal structure is located west of the Reactor Buildings. The Stack is a tapered, reinforced concrete structure, 500 feet high, and also includes a nearby, metal, radiation monitoring building. The Stack foundation is an octagonal concrete mat approximately 7 feet thick. The Stack is safety-related and seismic Class I. The Stack provides an elevated discharge of treated gaseous waste to meet the requirements of 10 CFR 100. The radiation monitoring building houses radiation monitoring equipment, which is within the scope of license renewal, and the building is part of the Stack license renewal structure.

Components not included in the evaluation boundary of the Stack are component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), penetration seals, and ventilation dampers. Penetration seals, doors and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, platforms, hatches, and other miscellaneous steel are evaluated with the Miscellaneous Steel commodity group. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Stack. The Stack is further discussed in UFSAR Section 12.2.7 and Appendix C. The Stack is shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Stack meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Stack meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Stack is not in scope under 10 CFR 54.4(a)(3) because it is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide for the discharge of treated gaseous waste to meet the requirements of 10 CFR 50.67 or 10 CFR 100. 10 CFR 54.4(a)(1)

2. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

3. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

UFSAR References

5.3.3
9.4
11.4
12.2.7
Appendix C

Second License Renewal Boundary Drawings

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Table 2.4-18 Stack
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Gaseous Release Path
	Shelter and Protection, Shielding, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Gaseous Release Path
	Shelter and Protection, Shielding, Structural Support
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support
Concrete: Interior (accessible areas)	Gaseous Release Path
	Shelter and Protection, Shielding, Structural Support
Concrete: Interior (inaccessible areas)	Gaseous Release Path
	Shelter and Protection, Shielding, Structural Support
Hatches/Plugs	Direct Flow, Shelter and Protection
Roofing	Shelter and Protection
Steel components: structural steel	Structural Support
Structural Miscellaneous - Siding	Shelter and Protection

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

Table 3.5.2-18 Stack
Summary of Aging Management Evaluation

2.4.19 Station Blackout Structure and Foundations

Description

The Station Blackout Structure and Foundations consist of the onsite PBAPS SBO substation structures and foundations, the PBAPS SBO marine cable manhole, and associated site underground duct banks between the marine cable manhole and the SBO substation structures. The Station Blackout Structure and Foundations also includes the offsite SBO marine cable manhole and the Susquehanna Substation structure and foundations at the offsite Conowingo Hydroelectric Plant (Dam).

The onsite PBAPS SBO substation consists of the SBO 34.5 kV and 13 kV outdoor switchgear structure and foundations, and the outdoor step-down transformer foundations. The SBO 34.5 kV and 13 kV switchgear structure, which houses the switchgear necessary to connect the SBO AAC source to PBAPS, is a pre-fabricated steel enclosure with double doors at either end of the structure to facilitate equipment transfer in and out of the structure as required. The SBO 34.5 kV and 13 kV switchgear structure is designed to protect the equipment from damage due to external weather exposure and is mounted on three reinforced concrete piers. The SBO substation stepdown transformer is mounted on a reinforced concrete foundation slab surrounded by oil retention pit walls. The PBAPS underground duct bank and a reinforced concrete manhole for the SBO marine cable, provide support, shelter, and protection to SBO cables connected to the marine cables routed to the offsite Susquehanna Substation. These onsite SBO structures and foundations are within the scope of license renewal.

The SBO alternate AC (AAC) source is powered from the offsite Susquehanna Substation that provides a dedicated station blackout circuit which is available for connection and is independent from the transmission grid from which normal offsite power is derived. The SBO AAC power is transmitted using a marine cable routed from the Susquehanna Substation to the PBAPS onsite SBO marine cable manhole. The offsite SBO structures, which consist of the Susquehanna Substation structures and foundations, a wooden takeoff pole, and a marine cable manhole, are within the scope of license renewal. The offsite Conowingo Hydroelectric Plant (Dam) (which supplies power to the Susquehanna Substation), is a separately operated and managed facility, and which is subject to the FERC mandated five-year inspection program.

Components not included in the evaluation boundary of the Station Blackout Structure and Foundations are component supports, electrical enclosures, doors and elastomeric seals, wooden takeoff pole, and electrical equipment and cables including marine cables. Conduit, cable trays, cabinets, enclosures, racks, frames, and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Doors, and seals and gaskets are evaluated in the Hazard Barriers and Elastomers commodity group. The wooden takeoff pole for the offsite Susquehanna Substation at the offsite Conowingo Hydroelectric Plant (Dam) is evaluated with Electrical Commodities. The associated SBO electrical equipment, cables, and submarine cable are evaluated with the Station Blackout System. Component supports other than the foundations mentioned above are evaluated with the Component Supports commodity group. Other PBAPS onsite switchgear buildings, breakers and transformer foundations, manholes and duct banks and substation structures also relied on or associated with SBO, and which supply normal offsite power, are evaluated with the Outdoor Electric Switchgear, North Substation, and also with Yard Structures.

The Station Blackout Structure and Foundation is discussed in UFSAR Sections 8.3.2.2 and 8.4.6.2. The Station Blackout Structure and Foundation structures are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Station Blackout Structure and Foundations is not in scope under 10 CFR 54.4(a)(1) because no portions of the structures are safety-related or relied upon to remain functional during and following design basis events. The Station Blackout Structure and Foundations is not in scope under 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures would not prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Station Blackout Structure and Foundations meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Station Blackout Structure and Foundations is not relied upon in any 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), or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

8.1
8.3.2.2
8.4.6

Second License Renewal Boundary Drawings

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Table 2.4-19 Station Blackout Structure and Foundations
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Structural Support
Concrete: Interior	Structural Support
Conowingo Hydroelectric Plant (Dam)	Shelter and Protection, Structural Support
Duct Banks	Shelter and Protection
Equipment supports and foundations	Structural Support
Manholes, Handholes & Duct Banks	Shelter and Protection, Structural Support
Metal components	Structural Support
Structural Miscellaneous - Decking (Roof)	Shelter and Protection, Structural Support
Structural Miscellaneous - Siding	Shelter and Protection, Structural Support

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

Table 3.5.2-19 Station Blackout Structure and Foundations
Summary of Aging Management Evaluation

2.4.20 Turbine Building and Main Control Room Complex

Description

The Turbine Building and Main Control Room Complex houses both turbine-generators, one for each unit, and other auxiliary plant equipment.

This building is founded on rock at various elevations. The external and some internal walls are concrete up to the operating floor. The structure above this level is metal siding and decking above a band of precast concrete wall panels, all supported by structural steel frames. Frames also support two turbine building cranes.

Each turbine-generator is mounted on a concrete pedestal. The pedestals are supported on a concrete mat and founded on rock. The turbine building is designed with the seismic design criteria for Zone 1 established by the Uniform Building Code, and is classified seismic Class II. The turbine building is located east of the two Reactor Buildings and is separated from them by a gap to accommodate movements of the structures during an earthquake.

The main control room complex consists of the main control room, the cable spreading room, computer room, battery rooms, and emergency switchgear rooms, which are located in the center portion of the turbine building. This portion of the building is designed and classified as a seismic Class I structure.

Components not included in the evaluation boundary of the Turbine Building and Main Control Room Complex are roofing, roof hatches, roof downspout drains, component supports, electrical enclosures (conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation), the building cranes, other miscellaneous cranes and hoists, hazard barriers (doors, dampers, fire rated barriers and enclosures, fire proofing material, penetration seals and sleeves, walls and slabs), and ventilation dampers. Roofing, penetration seals, doors and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Louvers, vents, roof scuttles, platforms, hatches, and other miscellaneous steel are evaluated with the Miscellaneous Steel commodity group. Roof downspouts drains are evaluated with the Plant Equipment and Floor Drain license renewal system, and discharge to the storm drain system. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, racks, frames and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. The building crane and other miscellaneous cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Turbine Building and Main Control Room Complex

The Turbine Building and Main Control Room Complex is discussed in UFSAR Section 12.2.2 and Appendix C. The Turbine Building and Main Control Room Complex are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Turbine Building and Main Control Room Complex meets 10 CFR 54.4(a)(1) because it is a safety-related structure that is relied upon to remain functional during and following design basis events. The Turbine Building and Main Control Room Complex meets 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Turbine Building and Main Control Room Complex also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4 (a)(1)

2. Provide centralized area for control and monitoring of nuclear safety-related equipment. 10 CFR 54.4 (a)(1)

3. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4 (a)(1). 10 CFR 54.4 (a)(2)

4. Provides structural support or restraint to SSCs in the scope of license renewal. 10 CFR 54.4(a)(2)

5. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4 (a)(3)

6. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4 (a)(3)

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

8. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4 (a)(3)

UFSAR References

12.2.2
Appendix C

Second License Renewal Boundary Drawings

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Table 2.4-20 Turbine Building and Main Control Room Complex Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier, Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	HELB/MELB Shielding
	Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Interior (inaccessible areas)	HELB/MELB Shielding
	Missile Barrier, Shelter and Protection, Shielding, Structural Pressure Barrier, Structural Support
Equipment supports and foundations	Structural Support
Hatches/Plugs	Shelter and Protection, Shielding, Structural Support
Masonry walls: Interior	Shelter and Protection, Shielding, Structural Support
Metal components	Structural Support
Precast Concrete- Beams and Panels	Shelter and Protection, Shielding, Structural Support
Sliding surfaces	Structural Support
Steel components: structural steel	Structural Support
Structural Miscellaneous - Decking	Shelter and Protection, Structural Support
Structural Miscellaneous - Missile Barrier	Missile Barrier
Structural Miscellaneous - Shielding	Shielding
Structural Miscellaneous - Siding	Shelter and Protection

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

Table 3.5.2-20 Turbine Building and Main Control Room Complex Summary of Aging Management Evaluation

2.4.21 Watertight Dikes

Description

The watertight dikes around the refueling water storage tank, the condensate storage tanks, and the torus dewatering tank, which is also called the torus water storage tank, were provided to contain any spills or overflow to support the liquid radwaste system design basis. The liquid radwaste system is designed such that discharge concentrations are less than 10 CFR Part 20 limits. Water collected within the dikes is either directed to the radwaste system for processing or released to the plant storm drain system. The dikes are designed to withstand the effects of the maximum ground acceleration due to the design earthquake as indicated in UFSAR Sections 9.2 and 12.2.16, but are not classified seismic Class I structures in UFSAR Appendix C.1.2, nor are the dikes credited for a regulated event. The Watertight Dikes are not relied upon to prevent or mitigate the consequences of an accident that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR Part 100 or 10 CFR 50.67. Structural separations are included between the dikes and the shared walls of buildings, but the dikes are not physically separated by sufficient distance to preclude potential impact to adjacent seismic Class I structures. In addition, the torus dewatering tank dike provides support for a pipe identified as necessary for fire safe shutdown. The reinforced concrete portions of the Watertight Dikes are therefore in scope for license renewal.

Components not included within the evaluation boundary of Watertight Dikes includes Component Supports and tank foundations. Component Supports are evaluated with the Component Supports Commodity Group. Tank foundations are evaluated with Yard Structures.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Watertight Dikes.

The Watertight Dikes are discussed in UFSAR Sections 9.2, 12.2.16, and Appendix C. The Watertight Dikes are shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Watertight Dikes are not in scope under 10 CFR 54.4(a)(1) because no portions of the structures are safety-related or relied upon to remain functional during and following design basis events. The Watertight Dikes meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Watertight Dikes also meet 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The Watertight Dikes are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49), Anticipated Transient Without Scram (10 CFR 50.62), or Station Blackout (10 CFR 50.63).

Intended Functions

1. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

2. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48).
10 CFR 54.4(a)(3)

UFSAR References

9.2.4
9.2.9
12.2.16
Appendix C

Second License Renewal Boundary Drawings

SLR-PB-S-001

Table 2.4-21 Watertight Dikes
Components Subject to Aging Management Review

Component Type	Intended Function
Concrete: Above-grade exterior (accessible areas)	Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Structural Support

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

Table 3.5.2-21 Watertight Dikes
Summary of Aging Management Evaluation

2.4.22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.)

Description

Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) includes various structures and components in the yard, inside of the Protected Area, around the power block and circulating water pumphouse. The Yard Structures consist of various conduit duct banks, electrical and other manholes, valve pits, pipe tunnels and trenches, circulating water discharge tunnel, retaining walls, roads, storm drainage, lighting poles, storage tank foundations, and other miscellaneous yard features. Yard Structures determined to be in scope for license renewal are various electrical manholes which include the curbs, manhole access covers, and the buried duct banks that carry electrical cables in scope for license renewal, the service water pipe tunnel below the administration building, condensate storage tank foundations, refueling water storage tank foundation, access manholes and foundations for underground diesel oil storage tanks, and the high pressure service water valve pit. Other tank foundations, supports, pipe trenches, manholes, valve pits, roadways, lighting poles, storm drains, tunnels, and other components within the boundary of Yard Structures were evaluated and determined to be not in scope since the components do not perform an intended function.

Components not included in the evaluation boundary of the Yard Structures, which are in the yard area around the powerblock, are component supports; electrical enclosures such as cabinets, racks and frames, enclosures, and panels for electrical equipment and instrumentation; raceway such as conduit, cable trays, and tubing tray; fire protection system components (walls, oil retaining dikes, fireproofing material, fire hazard barriers, fire doors, and penetration seals and sleeves); cable trenches, ductbanks and control buildings in substations and associated with SBO or the Outdoor Electric Switchgear, North Substation, towers and tower foundations between the powerblock and substations, outdoor transformer foundations and the walls that separate them, switchgear buildings, and the SBO structures including SBO manhole and substation. Penetration seals, and other seals are evaluated with the Hazard Barriers and Elastomers commodity group. Miscellaneous steel is evaluated with the Miscellaneous Steel commodity group which includes manhole covers and hatch type metal covers. Component Supports are evaluated in the Component Supports commodity group. Conduit, cable trays, cabinets, enclosures, and panels for electrical equipment and instrumentation are evaluated in the Electrical and Instrumentation Enclosures and Raceways commodity group. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs - including oil retaining dikes and walls that separate transformers) are evaluated with the Fire Protection System. Cable trenches, ductbanks and control buildings in substations, towers and tower foundations between the powerblock and substations, and outdoor transformer foundations, and switchgear buildings are evaluated with the Outdoor Electric Switchgear, North Substation. SBO structures including the onsite SBO manhole and substation, are evaluated with the Station Blackout Structure and Foundations. Any mechanical and electrical systems and components housed inside or supported by the Yard Structures or within any manhole or valve pit structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities. The yard areas in the north and south substations were evaluated as part of the Outdoor Electric Switchgear, North Substation. The yard areas around the Conowingo pond were evaluated with the Intake Screen Structure, Cooling Towers, and Discharge Control Structures.

Refer to the "Components Subject to Aging Management Review" table below for a list of components included in the boundary of the Yard Structures.

The Yard Structures are further discussed in UFSAR FPP Section 6.3. The Yard Structures are partially shown on the second license renewal boundary drawing listed below.

Reason for Scope Determination

The Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) meet 10 CFR 54.4(a)(1) because it contains safety-related structures that are relied upon to remain functional during and following design basis events. The Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) meet 10 CFR 54.4(a)(2) because failure of nonsafety-related portions of the structures could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). The Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) also meet 10 CFR 54.4(a)(3) because the Yard Structures contain structures relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). The Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) are not relied upon in any safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) or Anticipated Transient Without Scram (10 CFR 50.62).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)

2. Provide physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

3. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

4. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

FPP 6.3

Second License Renewal Boundary Drawings

SLR-PB-S-001

Table 2.4-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) Components Subject to Aging Management Review

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete elements: All (Foundation Condensate Storage Tanks)	Structural Support
Concrete elements: All (Foundation Diesel Storage Tanks)	Structural Support
Concrete elements: Anchors	Structural Support
Concrete elements: Curbs	Direct Flow
Concrete elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Interior (accessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Concrete: Interior (inaccessible areas)	Missile Barrier, Shelter and Protection, Structural Support
Manholes, Handholes & Duct Banks	Shelter and Protection, Structural Support
Steel components: structural steel	Structural Support

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

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) Summary of Aging Management Evaluation

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL

The determination of electrical systems that fall within the scope of license renewal is made through the application of the process described in Section 2.1. The results of the electrical systems scoping review are contained in Section 2.2.

Subsection 2.1.6.1 provides the screening methodology for determining which electrical components and commodity groups within the scope of 10 CFR 54.4 meet the requirements contained in 10 CFR 54.21(a)(1). The electrical commodity groups that meet those screening requirements are identified in this section. These identified electrical commodity groups consequently require an aging management review.

As described in Subsection 2.1.6.1, the screening was performed on a commodity group basis for the in scope electrical and I&C systems as well as the electrical and I&C component types associated with in scope mechanical systems listed in Table 2.2-1.

Components which support or interface with electrical and I&C components, for example, cable trays, conduits, instrument racks, panels and enclosures, are assessed as part of the Component Supports commodity group in Section 2.4.4. The one exception is the wooden pole in the station blackout alternate AC power supply which is addressed with electrical components and commodities.

2.5.1 ELECTRICAL SYSTEMS

The results of the electrical system scoping review are contained in Section 2.2. Additional system details are included in the UFSAR Sections 7 and 8. In addition to the electrical and I&C systems and components, certain switchyard components are credited to restore offsite power following a station blackout (SBO). The boundary for offsite power restoration following an SBO is shown in a simplified diagram in Figure 2.1-2. The simplified diagram also shows the Alternate AC (ACC) power source for the SBO coping period.

2.5.2 ELECTRICAL COMMODITIES

2.5.2.1 Identification of Electrical Commodities

The first step of the screening process for electrical commodities is to use plant documentation to identify the electrical components and commodities within the electrical, I&C and mechanical systems based on plant design documentation, drawings, and the Passport equipment database, as well as by interfacing with the parallel mechanical and civil screening efforts. The electrical components and commodities identified at PBAPS are listed below. This list includes electrical components and commodities identified in NUREG-2192, Table 2.1-6, as applicable at PBAPS.

Electrical Components and Commodities for In Scope Systems:

- Annunciators
- Batteries
- Battery Charger
- Cable Connections (Metallic Parts)
- Cable Tie Wraps
- Chargers
- Circuit Breakers
- Communication Equipment
- Computers
- Controllers
- Converters
- Electric Heaters
- Electrical Controls and Panel Internal Assemblies
- Electrical Insulation for Electrical Cables and Connections
- Electrical Penetrations
- Elements, Sensors, Thermocouples, Transducers
- Fuses
- Fuse Holders (part and not part of active equipment)
- Generators, Motors
- Heat Trace
- High Voltage Electrical Insulators
- Indicators
- Inverters
- Isolators
- Light Bulbs
- Metal Enclosed Bus
- Meters
- Modifier (analog/digital input/output modules, signal converters, pre-amps, etc.)
- Power Supplies
- Radiation Monitors
- Recorders
- Regulators
- Relays
- Signal Conditioners
- Solenoid Operators
- Solid State Devices
- Splices
- Switches
- Switchgear, Load Centers, Motor Control Centers, Distribution Panels
- Switchyard Bus and Connections
- Terminal Blocks
- Transformers
- Transmission Conductors
- Transmission Connectors
- Transmitters
- Uninsulated Ground Conductors
- Wooden Pole

2.5.2.2 <u>Application of Screening Criterion 10 CFR 54.21 (a)(1)(i) to the Electrical Components and Commodities</u>

Following the identification of the electrical components and commodities, the criteria of 10 CFR 54.21 (a)(1)(i) were applied to identify components and commodities that perform their functions without moving parts or without a change in configuration or properties. The following electrical commodities were determined to meet the screening criteria of 10 CFR 54.21 (a)(1)(i):

- Cable Connections (Metallic Parts)
- Cable Tie Wraps
- Electrical Insulation for Electrical Cables and Connections
- Electrical Penetrations
- Fuse Holders (not part of active equipment)
- High Voltage Electrical Insulators
- Metal Enclosed Bus
- Splices
- Switchyard Bus and Connections
- Terminal Blocks
- Transmission Conductors
- Transmission Connectors
- Uninsulated Ground Conductors
- Wooden pole

2.5.2.3 <u>Elimination of Electrical Commodity Groups With No License Renewal Intended Functions</u>

The following electrical commodities were determined to not have a license renewal intended function:

<u>Cable Tie Wraps</u>

Tie wraps are used in cable installations as cable ties. Cable ties hold groups of cables together for restraint and ease of maintenance. Cable ties are used to bundle wires and cables together to keep the wire and cable runs neat and orderly. Cable ties are used to restrain wires and cables within raceways to facilitate cable installation. There are no current license basis requirements for PBAPS that cable tie wraps remain functional during and following design basis events. Cable ties are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways at PBAPS. The seismic qualification of cable trays does not credit the use of cable ties. Cable tie wraps are not credited in the PBAPS design basis in terms of any 10 CFR 54.4 intended function. Therefore, cable tie wraps are not within the scope of license renewal and therefore, are not subject to aging management review.

<u>Uninsulated Ground Conductors</u>

The uninsulated ground conductor commodity is comprised of grounding cable and associated connectors. Ground conductors are provided for equipment and personnel protection. They do not perform an intended function for license renewal. Therefore, uninsulated ground conductors are not within the scope of license renewal and therefore, are not subject to aging management review.

2.5.2.4 Application of Screening Criteria 10 CFR 54.21 (a)(1)(ii) to Electrical Commodities

The 10 CFR 54.21 (a)(1)(ii) screening criterion was applied to the specific commodities that remained following application of the 10 CFR 54.21 (a)(1)(i) criterion. 10 CFR 54.21 (a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical commodities identified for exclusion by the criteria of 10 CFR 54.21 (a)(1)(ii) are electrical and I&C components and commodities included in the Environmental Qualification of Electric Equipment aging management program. This is because electrical and I&C components and commodities included in the EQ Program have defined qualified lives and are replaced prior to the expiration of their qualified lives. No electrical and I&C components and commodities within the EQ Program are subject to aging management review in accordance with the screening criteria of 10 CFR 54.21 (a)(1)(ii). See Section 4.4 for the TLAA evaluation of the Environmental Qualification of Electric Equipment aging management program. The remaining commodities, all or part of which are not in the EQ Program, require aging management review and are discussed below.

2.5.2.5 Electrical Commodities Subject to Aging Management Review

The electrical commodities subject to aging management review are identified in Table 2.5.2-1, along with the associated intended functions. These electrical commodities are further described below.

2.5.2.5.1 Cable Connections (Metallic Parts)

The Cable Connectors (Metallic Parts) commodity includes metallic portions of cable connections that are not included in the EQ Program. The metallic connections evaluated include splices, threaded connectors, compression type termination lugs, and terminal blocks. Therefore, Cable Connections (Metallic Parts) meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to aging management review.

2.5.2.5.2 Electrical Insulation for Electrical Cables and Connections

The insulated cables and connections commodities are separated for aging management review into subcategories based on their treatment in NUREG-2191:

- Electrical Insulation for Electrical Cables and Connections
  - Includes:
    - Electrical Penetration Pigtails
    - Splices
    - Insulating Portions of Terminal Blocks
    - Insulating Portions of Fuse Holders (not part of active equipment).
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
- Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Conductor Insulation for Inaccessible Low Voltage Power Cables
- Electrical Conductor Insulation for Inaccessible Medium Voltage Power Cables

Numerous insulated cables and connections are included in the EQ Program and, therefore, are not subject to an aging management review in accordance with the screening criteria of 10 CFR 54.21 (a)(1)(ii). Insulated cables and connections not included in the EQ Program meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

Insulated cables and connections inside the enclosure of an active device (e.g., motor leads and connections, cables and connections internal to relays, chargers, switchgear, transformers, power supplies) are maintained along with the other subcomponents inside the enclosure and are not subject to an aging management review.

2.5.2.5.3 Electrical Penetrations

A portion of the electrical penetrations at PBAPS are environmentally qualified. These electrical penetrations are evaluated as a time-limited aging analysis, Section 2.5.2.4, and are managed by the Environmental Qualification of Electric Equipment (B.3.1.3). For the remainder of the electrical penetrations, the electrical continuity of electrical penetration pigtails and associated connections that could potentially be exposed to an adverse localized environment is included in the evaluation for Electrical Insulation for Electrical Cables and Connections, Section 2.5.2.5.2. The shelter, protection and pressure boundary intended functions of electrical penetrations are included in the evaluation for Containment Structure, Section 2.4.5.

2.5.2.5.4 Fuse Holders (not part of active equipment)

The Fuse Holders commodity includes fuse holders that are not part of a larger active assembly and are not included in the EQ program. Both the metallic and non-metallic portions of fuse holders that are not part of a larger active assembly and are not included in the EQ program meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.5 High Voltage Electrical Insulators

The High Voltage Electrical Insulators’ intended function is to insulate (electrical) for Switchyard Bus, Transmission Conductors, and switchyard active components that are part of the circuits that supply power from the electric utility transmission system to plant buses, including connecting the alternate ac source in the event of a station blackout. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout event and during post fire safe shutdown, when offsite power is credited. High Voltage Electrical Insulators are not included in the EQ program. Therefore, High Voltage Electrical Insulators meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.6 Metal Enclosed Bus

The license renewal in scope metal enclosed bus at PBAPS are in the 4 kV and 13 kV power systems and are used to connect to and between outdoor 13 kV switchgear for offsite power sources, and to connect offsite power sources to safety-related 4 kV switchgear. These portions of the power distribution system are in scope for license renewal. The metal enclosed bus are not in the EQ Program. Therefore, metal enclosed bus meets the screening criterion of 10 CFR 54.21(a)(1)(ii) and is subject to aging management review.

2.5.2.5.7 Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors

The Switchyard Bus and Connections are part of the switchyard circuits that supply power from the utility transmission system to plant buses, including connecting the alternate ac source in the event of a station blackout. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout and during post fire safe shutdown when offsite power is credited. The Switchyard Bus and Connections are not included in the EQ program. Therefore, Switchyard Bus and Connections meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

The Transmission Conductors and the Transmission Connectors are part of the switchyard circuits that supply power from the electric transmission system to plant buses including connecting the alternate ac source in the event of a station blackout. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout and during post fire safe shutdown, when offsite power is credited. The Transmission Conductors and the Transmission Connectors are not included in the EQ program. Therefore, the Transmission Conductors and the Transmission Connectors meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.8 Wooden Pole

The in scope wooden pole is adjacent to the Susquehanna Substation. The wooden pole provides structural support for the conductors connecting the substation to PBAPS's station blackout submarine cable. The pole is constructed of yellow pine and chemically treated prior to installation. The installed pole has been analyzed to be able to withstand the severe weather conditions that may occur with a station blackout event. The wooden pole adjacent to the Susquehanna Substation is not part of the EQ program. Therefore, the wooden pole is subject to an aging management review.

Table 2.5.2-1 Electrical Commodities Subject to Aging Management Review

Commodity	Intended Function
Cable Connections (Metallic Parts)	Electrical Continuity
Electrical Insulation for Electrical Cables and Connections	Insulate (Electrical)
Fuse Holders (not part of active equipment):	Insulate (Electrical)
	Electrical Continuity
High Voltage Electrical Insulators	Insulate (Electrical)
Metal Enclosed Bus	Electrical Continuity
	Insulate (Electrical)
	Shelter, Protection
Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors	Electrical Continuity
Wooden Pole	Structural Support

The aging management review results for these commodities are provided in Table 3.6.2-1 Electrical Commodities – Summary of Aging Management Evaluation.

3.0 AGING MANAGEMENT REVIEW RESULTS

This section provides the results of the aging management review for those structures and components identified in Section 2.0 as being subject to aging management review.

Descriptions of the service environments that were used in the aging management review to determine aging effects requiring management are included in Table 3.0-1, Peach Bottom Service Environments. The environments used in the aging management reviews are listed in the Peach Bottom AMR Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the Peach Bottom Aging Management Review results to the NUREG-2191 results.

Most of the Aging Management Review (AMR) results information in Section 3 is presented in the following two tables:

- **Table 3.x.1** - where '3' indicates the LRA section number, 'x' indicates the subsection number from NUREG-2192, and '1' indicates that this is the first table type in Section 3. For example, in the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be number 3.1.1; in the Engineered Safety Features subsection, this table would be 3.2.1; and so on. For ease of discussion, this table will hereafter be referred to in this Section as "Table 1."

- **Table 3.x.2-y** - where '3' indicates the LRA section number, 'x' indicates the subsection number from NUREG-2192, and '2' indicates that this is the second table type in Section 3; and 'y' indicates the table number for a specific system. For example, for the Reactor Pressure Vessel and Internals System, within the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be 3.1.2-1 and for the Reactor Pressure Vessel Instrumentation System, it would be table 3.1.2-2. For the Containment Atmosphere Control and Dilution System, within the Engineered Safety Features (ESF) subsection, this table would be 3.2.2-1. For the next system within the ESF subsection, it would be table 3.2.2-2. For ease of discussion, this table will hereafter be referred to in this section as "Table 2."

<u>TABLE DESCRIPTION</u>

NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," contains the generic evaluation of existing plant programs. It documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the second extended period of operation. The evaluation results documented in NUREG-2191 indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components, within the scope of license renewal, without change. NUREG-2191 also contains recommendations on specific areas for which existing programs should be enhanced for license renewal. In order to take full advantage of NUREG-2191, a comparison between the PBAPS AMR results and the tables of NUREG-2191 has been performed. The results of that comparison are provided in Table 1 and Table 2.

Table 1

The purpose of Table 1 is to provide a summary comparison of how the facility aligns with the corresponding tables of NUREG-2192. The table is essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the first three columns, "New, Modified, Deleted, Edited Item", "ID" and "Type", have been replaced by an "Item Number" column and the "GALL-SLR Item" column has been replaced by a "Discussion" column.

The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The "Discussion" column is used to provide clarifying or amplifying information. The following are examples of information that might be contained within this column:

- "Further Evaluation Recommended" information or reference to where that information is located
- The name of a plant-specific aging management program being used, if applicable
- Exceptions to the NUREG-2192 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2192, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2192 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2192), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-2192 table row, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the aging management reviews for those components identified in SLRA Section 2 as being subject to aging management review. There is a Table 2 for each of the in-scope systems, structures, and commodities within each Chapter 3 Section grouping. For example, for Peach Bottom, the Engineered Safety Features System Group contains tables specific to the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Secondary Containment System, and Standby Gas Treatment System.

Table 2 consists of the following nine columns:

- Component Type
- Intended Function

- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-2191 Item
- NUREG-2192 Table 1 Item
- Notes

Component Type – The first column identifies all of the component types from Section 2 of the SLRA that are subject to aging management review. They are listed in alphabetical order.

Intended Function – The second column contains the license renewal intended functions for the listed component types. Definitions of intended functions are contained in Table 2.1-1.

Material – The third column lists the particular materials of construction for the component type.

Environment – The fourth column lists the environments to which the component types are exposed. Service environments are indicated and a list and description of these environments is provided in Table 3.0-1.

Aging Effect Requiring Management – As part of the aging management review process, the aging effects that are required to be managed in order to maintain the intended function of the component type are identified for the material and environment combination. These aging effects requiring management are listed in the fifth column.

Aging Management Programs – The aging management programs used to manage the aging effects requiring management are listed in the sixth column of Table 2. Aging management programs are described in Appendix B.

NUREG-2191 Item – Each combination of component type, material, environment, aging effect requiring management, and aging management program that is listed in Table 2, is compared to NUREG-2191, with consideration given to the standard notes, to identify consistency. Consistency is documented by noting the appropriate NUREG-2191 item number in the seventh column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column seven is left blank. Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

NUREG-2192 Table 1 Item – Each combination of component, material, environment, aging effect requiring management, and aging management program that has an identified NUREG-2191 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in the eighth column of Table 2. If there is no corresponding item in NUREG-2191, this field in column eight is left blank. The NUREG-2192 Table 1 Item allows correlation of the information from the two tables.

Notes – The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard lettered notes and, if applicable, plant-specific numbered notes.

The standard lettered notes (e.g., A, B, C) provide standard information regarding comparison of the Peach Bottom aging management review results with the NUREG-2191 Aging Management Table line item identified in the seventh column. In addition to the standard lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

TABLE USAGE

Table 1

The reviewer may evaluate each row in Table 1 by moving from left to right across the table. Since the Component, Aging Effect, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required. Summary plant-specific information is provided within the Discussion column to demonstrate how the Peach Bottom aging management review evaluations and aging management programs align with NUREG-2192. This may be in the form of descriptive information within the Discussion column, or the reviewer may be referred to other locations within the SLRA for further information.

Table 2

Table 2 contains all of the Aging Management Review information for the plant, including whether or not it aligns with NUREG-2191 recommendations. For a given row within the table, the reviewer is able to see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this is 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 is blank, no corresponding combination in NUREG-2191 was found. As the reviewer continues across the table from left to right, within a given row, the next column is labeled NUREG-2192 Table 1 Item. If there is a reference number in this column, the reviewer is able to use that reference number to locate the corresponding row in Table 1 and see how the aging management program for this particular combination aligns with NUREG-2191.

Table 2 provides the reviewer with a means to navigate from the components subject to Aging Management Review (AMR) in SLRA Section 2 all the way through the evaluation of the programs that will be used to manage the effects of aging of those components.

A listing of the acronyms used in this section is provided in Section 1.6.

Cumulative Fatigue Damage and TLAAs in Table 2

A fatigue analysis is considered to be a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3 when it is within the current licensing basis and is based upon transient cycle assumptions associated with 60 years of plant operation. Additionally, there are other TLAAs that affect identified aging effects for specific components. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1).

Table 1 and Table 2 include an entry in the Aging Management Program column indicating "TLAA" for each line item where the component for which a TLAA has been identified. See SLRA Section 4 for details regarding the PBAPS design bases, TLAAs identified, and TLAA evaluations for the second period of extended operation.

Table 3.0-1 Peach Bottom Service Environments		
Peach Bottom AMR Environment	**Description**	**Corresponding NUREG-2191 Environments**
10 CFR 50.49 EQ Environments	This environment is used for areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment, in which the requirements of 10 CFR 50.49 would be applicable.	Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment.
Adverse Localized Environment	The Adverse Localized Environment represents conditions with excessive heat, radiation, moisture, sometimes in the presence of oxygen. The effect can be concentrated or applicable to a general plant area.	Adverse localized environment caused by heat, radiation, or moisture
Adverse Localized Environment Caused by Significant Moisture	This environment is the same as the Adverse Localized Environment, except that it is caused by the presence of significant moisture.	Adverse localized environment caused by significant moisture
Air – Dry	The Air – Dry environment is used for air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants. Use of this term is only associated with internal air environments located downstream of the compressed air system air dryers and filters.	Air – dry
Air – Indoor, Controlled	The Air – Indoor, Controlled environment is one in which the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. For electrical components and structures, the controlled environment must be sufficient to show that the electrical component(s) or structure(s) are not subjected to the cited aging effect(s) (e.g., reduced insulation resistance). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in scope components exists when citing the air-indoor controlled environment.	Air – indoor, controlled

Table 3.0-1
Peach Bottom Service Environments

Peach Bottom AMR Environment	Description	Corresponding NUREG-2191 Environments
Air – Indoor, Uncontrolled	The Air - Indoor Uncontrolled environment is for indoor locations that are sheltered/protected from weather. Air temperatures and surface temperatures of components in this environment are higher than the dew point (i.e. condensation can occur, but only rarely). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in scope components exists when citing the air–indoor uncontrolled environment.	Air Air - indoor, uncontrolled System temperature up to 288°C (550°F)
Air – Outdoor	The Air – Outdoor environment includes atmospheric air exposed to weather and ambient temperatures and humidity (with a relative humidity up to 100%). This environment may be subject to periodic wetting and wind.	Air Air – outdoor
Closed Cycle Cooling Water	The Closed Cycle Cooling Water environment includes treated water subject to the Closed Treated Water Systems program, which is Aging Management Program XI.M21A in NUREG-2191. The Closed Treated Water Systems program relies on maintenance of system corrosion inhibitor concentrations within specified limits of Electric Power Research Institute Technical Report 1007820 to minimize corrosion. Demineralized water is treated with corrosion inhibitors, pH control agents, or biocides, as needed.	Closed-cycle cooling water
Closed Cycle Cooling Water > 140 F	The Closed Cycle Cooling Water >140 F environment is the same as the Closed Cycle Cooling Water environment, except the Closed Cycle Cooling Water >140 F environment is used for components with an operating temperature >140 F that are constructed of stainless steel.	Closed-cycle cooling water Closed-cycle cooling water >60°C (>140°F)
Concrete	The Concrete environment is one where components are embedded in concrete. This environment is considered aggressive if the concrete pH is <5.5, or chloride concentration is >500 ppm, or sulfate concentration is > 1,500 ppm.	Concrete

Table 3.0-1 Peach Bottom Service Environments		
Peach Bottom AMR Environment	**Description**	**Corresponding NUREG-2191 Environments**
Condensation	The Condensation environment is an air environment containing warm or moist air where condensation may occur and periodically wet the component surface. This environment includes air with enough moisture to facilitate loss of material caused by general, pitting and crevice corrosion for most common materials. It also facilitates cracking in those materials susceptible to stress corrosion cracking due to the potential for internal or external surface contamination. Although condensation may occur, it is not expected to be significant enough to result in ponding and pooling that can pose a spatial interaction concern. Ponding and pooling to this degree, as would expected to be found in HVAC drip pans and drains lines, is considered Waste Water. The condensation air environment is used for air drawn inside ventilation systems and air spaces within tanks. Certain components reside inside larger components such that their external surfaces are exposed to the internal environment of the larger component (e.g., tubes in air coolers). For these situations, Condensation is designated as the external environment. The Condensation environment is also used for certain insulated components. Because of air in-leakage through minor gaps in insulation, condensation can occur underneath the insulation on components when the operating temperature of the component is below the dew point of the air on the external surfaces of the insulation.	Condensation Reactor coolant [1]
Diesel Exhaust	The Diesel Exhaust environment represents the exhaust from diesel engines. It is considered to have the potential to concentrate contaminants and be subject to wetting through condensation.	Diesel Exhaust
Fuel Oil	The Fuel Oil environment includes fuel oil for the emergency diesel generators, diesel-driven fire pumps, etc. Water contamination of fuel oil is assumed.	Fuel oil

Table 3.0-1
Peach Bottom Service Environments

Peach Bottom AMR Environment	Description	Corresponding NUREG-2191 Environments
Gas	The Gas environment includes inert or nonreactive gases where aging effects are not expected to degrade the ability of the structure or component to perform its intended function for the subsequent period of extended operation.	Gas
Groundwater/Soil	The Groundwater/Soil environment is the external environment for structural components buried in the soil where there is groundwater present.	Ground water/soil Soil
Lubricating Oil	Lubricating oils are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication. Water contamination of lubricating oil is assumed. Hydraulic fluids are also included within this environment.	Lubricating oil
Raw Water	The Susquehanna River, as well as ground water from wells, provide the sources of raw water utilized by PBAPS. Raw water is also rain or ground water. Raw water is water that has not been demineralized or treated to any significant extent. This can include water for use in open-cycle cooling water and fire protection systems. Raw water includes Raw Water (potable) that is used for drinking or other personal use and has been filtered and chlorinated, and is therefore not susceptible to MIC. Raw water in plant systems may have been rough filtered to remove large particles and may contain a biocide additive for control of micro- and macro-organisms.	Raw water Raw water (potable) Water flowing or standing
Reactor Coolant	The Reactor Coolant environment is treated water used within the reactor coolant system to transfer heat from the fuel inside the reactor vessel core. The Reactor Coolant environment also includes Steam. The temperature of the Reactor Coolant environment is assumed to be >482 °F. The Reactor Coolant environment has been selected for the Reactor Pressure Vessel and Internals system for consistency with the NUREG-2191 terminology.	Reactor coolant Reactor coolant, neutron flux Treated Water [2]

Table 3.0-1
Peach Bottom Service Environments

Peach Bottom AMR Environment	Description	Corresponding NUREG-2191 Environments
Reactor Coolant and Neutron Flux	The Reactor Coolant and Neutron Flux environment is used for components within the reactor vessel and internals system that are in contact with reactor coolant and are exposed to neutron fluence projected to exceed 1.0 x 10^{17} n/cm^2 (E >0.1 MeV) within 80 years. The temperature of the Reactor Coolant and Neutron Flux environment is always assumed to be >482°F.	Reactor coolant Reactor coolant >250°C (>482°F), neutron flux Reactor coolant, neutron flux
Sodium Pentaborate Solution	The Sodium Pentaborate Solution environment is associated with sodium pentaborate, used in the Standby Liquid Control system.	Sodium pentaborate solution Treated water
Soil	The Soil environment is the external environment for components buried in the soil, and it includes ground water in the soil.	Soil Groundwater/soil
Steam	The Steam environment is the internal environment associated with dry steam, such as main steam up to the main turbine. The Water Chemistry Program (XI.M2) and One-Time Inspection Program are used for managing aging effects in dry steam environments. Wet steam is included within the Treated Water environment. Wet steam environments (i.e., locations where there is a high potential of condensation of the steam) for PBAPS are described as either Treated Water or Reactor Coolant, depending upon location, but may use the NUREG-2191 steam environment for cumulative fatigue damage or loss of material aging effects.	Steam Reactor coolant Treated water Treated water >60°C (>140°F)
Treated Water	Treated water is demineralized water or chemically purified water and is the base water for all clean systems. Depending on the system, treated water may require further processing. Treated water may be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. The treated water environment also includes wet steam. Dry steam, such as main steam up to the high pressure turbine, is addressed as its own environment.	Treated water Air – indoor, uncontrolled [1] Reactor coolant [1] Steam

Table 3.0-1
Peach Bottom Service Environments

Peach Bottom AMR Environment	Description	Corresponding NUREG-2191 Environments
Treated Water > 140 F	The Treated Water >140 F environment is the same as the Treated Water environment, except the Treated Water >140 F environment is used for systems operating at temperatures >140 F that are constructed of stainless steel. For materials other than stainless steel, the Treated Water environment is used. The Treated Water >140 F environment includes wet steam. Dry steam, such as main steam, is addressed as its own environment.	Treated water >60°C (>140°F) Treated water Reactor coolant [1]
Treated Water > 200 F	The Treated Water >200 F environment is the same as the Treated Water environment, except the Treated Water >200 F environment is to be selected for Reactor Water Cleanup (RWCU) System, piping and piping components outboard of the second containment isolation valves with a diameter ≥4 inches nominal pipe size and for RCPB Class 1 piping, piping components greater than or equal to 4 NPS.	Reactor coolant [1] Treated water >93°C (>200°F)
Treated Water > 482 F	The Treated Water >482 F environment is the same as the Treated Water environment, except the Treated Water >482 F environment is to be selected for components with an operating temperature >482 F that are constructed of Cast Austenitic Stainless Steel (CASS). The Treated Water >482 F environment includes wet steam. Dry steam, such as main steam up to the high pressure turbine, is addressed as its own environment.	Reactor coolant [1] Reactor coolant >250°C (>482°F) Treated water >60°C (>140°F)
Underground	The Underground environment is used for piping and tanks that are below grade, but are contained within a tunnel or vault such that they are in contact with air.	Underground

Table 3.0-1 Peach Bottom Service Environments		
Peach Bottom AMR Environment	**Description**	**Corresponding NUREG-2191 Environments**
Waste Water	Waste Water includes radioactive, potentially radioactive, or non-radioactive waters that are collected from equipment and floor drains, vent system drains, and waters processed by the radwaste system. Waste water may contain contaminants, including oil, depending on location, as well as treated water that is not monitored by a chemistry program. Collected water in HVAC drip pans and HVAC drain lines is considered Waste Water.	Waste water
Water – Flowing	The Water – Flowing environment is water that is refreshed, thus having larger impact on leaching; this can be rain water, raw water, groundwater, groundwater intrusion, or flowing water under a foundation.	Water – flowing

1. This environmental alignment is only utilized for TLAA related line items. Differences between the NUREG-2191 environment and the PBAPS AMR environment do not affect aging management of the cumulative fatigue damage aging effect for the applicable components.
2. This environmental alignment is utilized for line items in which long term loss of material is an applicable aging effect, which are managed by the One-Time Inspection (B.2.1.21) program. Differences between the NUREG-2191 environment and the PBAPS AMR environment do not affect aging management of long-term loss of material aging effect for the applicable components.

3.1 AGING MANAGEMENT OF REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

3.1.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.1, Reactor Vessel, Internals, and Reactor Coolant System, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Pressure Vessel and Internals System (2.3.1.1)
- Reactor Pressure Vessel Instrumentation System (2.3.1.2)
- Reactor Recirculation System (2.3.1.3)
- Fuel Assemblies (2.3.1.4)

3.1.2 RESULTS

The following tables summarize the results of the aging management review for Reactor Vessel, Internals, and Reactor Coolant System.

Table 3.1.2-1 Reactor Pressure Vessel and Internals System - Summary of Aging Management Evaluation

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System - Summary of Aging Management Evaluation

Table 3.1.2-3 Reactor Recirculation System - Summary of Aging Management Evaluation

Table 3.1.2-4 Fuel Assemblies - Summary of Aging Management Evaluation

3.1.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.1.2.1.1 Reactor Pressure Vessel and Internals System

Materials

The materials of construction for the Reactor Pressure Vessel and Internals System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Nickel Alloy Cladding
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Cast Austenitic Stainless Steel (CASS)

- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Nickel Alloy
- Stainless Steel
- Stainless Steel Bolting
- X-750 alloy

Environments

The Reactor Pressure Vessel and Internals System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Gas
- Reactor Coolant
- Reactor Coolant and Neutron Flux

Aging Effects Requiring Management

The following aging effects associated with the Reactor Pressure Vessel and Internals System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Pressure Vessel and Internals System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Penetrations (B.2.1.6)
- BWR Stress Corrosion Cracking (B.2.1.5)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Vessel Internals (B.2.1.7)
- Bolting Integrity (B.2.1.10)

- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Neutron Fluence Monitoring (B.3.1.2)
- One-Time Inspection (B.2.1.21)
- Reactor Head Closure Stud Bolting (B.2.1.3)
- Reactor Vessel Material Surveillance (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.1.2 Reactor Pressure Vessel Instrumentation System

Materials

The materials of construction for the Reactor Pressure Vessel Instrumentation System components are:

- Carbon and Low Alloy Steel Bolting
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel

Environments

The Reactor Pressure Vessel Instrumentation System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Reactor Pressure Vessel Instrumentation System components require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Pressure Vessel Instrumentation System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.1.3 Reactor Recirculation System

Materials

The materials of construction for the Reactor Recirculation System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Ductile Iron
- Glass
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Recirculation System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water > 140 F
- Condensation
- Lubricating Oil
- Treated Water
- Treated Water > 140 F
- Treated Water > 200 F

- Treated Water > 482 F

Aging Effects Requiring Management

The following aging effects associated with the Reactor Recirculation System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Recirculation System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- TLAA
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)
- Water Chemistry (B.2.1.2)

3.1.2.1.4 Fuel Assemblies

Materials

The materials of construction for the Fuel Assemblies components are:

- Not Applicable (Fuel Assemblies are short-lived components)

Environments

The Fuel Assemblies components are exposed to the following environments:

- Not Applicable

Aging Effects Requiring Management

The following aging effects associated with the Fuel Assemblies components require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Assemblies components:

- None

3.1.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Reactor Vessel, Internals, and Reactor Coolant System, those programs are addressed in the following subsections.

3.1.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs 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," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Table 3.1.1 Item Number 3.1.1-001: This item evaluates steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of steel reactor vessel closure flange assembly components is evaluated and dispositioned as a TLAA for the Reactor Pressure Vessel and Internals System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-003: This item evaluates stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant with neutron flux for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of stainless steel and nickel alloy reactor vessel internal components is evaluated and dispositioned as a TLAA for the Reactor Pressure Vessel and Internals System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-004: This item evaluates steel reactor vessel support skirt, and attachment welds for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel reactor vessel external attachments, support skirt, and welds is evaluated and dispositioned as a TLAA for the Reactor Pressure Vessel and Internals System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-006: This item evaluates steel (with or without nickel alloy or stainless steel cladding), stainless steel, and nickel alloy reactor coolant pressure boundary components including piping, piping components, and other reactor coolant pressure boundary components exposed to reactor coolant for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel and stainless steel Class 1 piping, piping components is evaluated and dispositioned as a TLAA for the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-007: This item evaluates stainless steel, steel (with or without nickel alloy or stainless steel cladding), and nickel alloy reactor vessel components including nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds exposed to reactor coolant for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel, carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel penetrations, nozzles, safe ends, vessel internal attachments, vessel shell components, and associated welds is evaluated and dispositioned as a TLAA for the Reactor Pressure Vessel and Internals System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-011: This item evaluates steel and stainless steel pump and valve closure bolting exposed to high temperature and thermal cycles for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon and low alloy steel bolting, high strength low alloy steel bolting, and stainless steel bolting is evaluated and dispositioned as a TLAA for the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1.1-002, Item Number 3.1.1-005, Item Number 3.1.1-008, Item Number 3.1.1-009, and Item Number 3.1.1-010: These items are applicable to PWRs only, and therefore are not used for PBAPS.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

1. *Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program relies on control of water chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot*

attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.1.1 Item Number 3.1.1-012: This item is applicable to PWRs only, and therefore is not used for PBAPS.

2. *Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The existing program relies on control of secondary water chemistry to mitigate corrosion. However, some applicants have replaced only the bottom part of their recirculating SGs, generating a cut in the middle of the transition cone, and, consequently, a new transition cone closure weld. It is recommended that volumetric examinations be performed in accordance with the requirements of ASME Code Section XI for upper shell and lower shell-to-transition cones with gross structural discontinuities for managing loss of material due to general, pitting, and crevice corrosion in the welds for Westinghouse Model 44 and 51 SGs, where a high-stress region exists at the shell-to-transition cone weld.*

   The new continuous circumferential weld, resulting from cutting the transition cone as discussed above, is a different situation from the SG transition cone welds containing geometric discontinuities. Control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. The new transition area weld is a field weld as opposed to having been made in a controlled manufacturing facility, and the surface conditions of the transition weld may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion than those of the upper and lower transition cone welds. Crediting of the ISI program for the new SG transition cone weld may not be an effective basis for managing loss of material in this weld, as the ISI criteria would only perform a VT-2 visual leakage examination of the weld as part of the system leakage test performed pursuant to ASME Code Section XI requirements. In addition, ASME Code Section XI does not require licensees to remove insulation when performing visual examination on nonborated treated water systems. Therefore, the effectiveness of the chemistry control program should be verified to ensure that loss of material due to general, pitting and crevice corrosion is not occurring.

   For the new continuous circumferential weld, further evaluation is recommended to verify the effectiveness of the chemistry control program. A one-time inspection at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. Furthermore, this issue is limited to replacement of recirculating SGs with a new transition cone closure weld.

Table 3.1.1 Item Number 3.1.1-012: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

1. *Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

   Table 3.1.1 Item Number 3.1.1-013: This item addresses loss of fracture toughness due to neutron irradiation embrittlement in steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux. The PBAPS reactor vessel beltline shell, nozzle, and weld components are carbon or low alloy steel with stainless steel cladding. The evaluation of neutron irradiation embrittlement for all ferritic reactor vessel shell components and welds that have a projected neutron fluence value greater than 1 x 10^{17} n/cm^2 (E>1 MeV) at the end of the second license renewal term is performed as a TLAA as discussed in Section 4.2.

2. *Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel material surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The reactor vessel material surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.*

   In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal (SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

   A neutron fluence monitoring program may be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the plant's reactor vessel neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "acceptance criteria" and "review procedure" guidance in SRP-SLR Section 4.2. For those applicants that determine it is appropriate to include a neutron fluence monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable neutron fluence monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."

Table 3.1.1 Item Number 3.1.1-014: This item addresses loss of fracture toughness due to neutron irradiation embrittlement in steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux. The Reactor Vessel Material Surveillance (B.2.1.20) program in conjunction with the Neutron Fluence Monitoring (B.3.1.2) program will be implemented to manage loss of fracture toughness due to neutron irradiation embrittlement of the carbon or low alloy steel with stainless steel cladding reactor vessel beltline components and welds exposed to a reactor coolant and neutron flux environment. The Reactor Vessel Material Surveillance (B.2.1.20) program meets the requirements of 10 CFR Part 50, Appendix H. The proposed surveillance capsule withdrawal schedule is included in the Reactor Vessel Material Surveillance (B.2.1.20) program. The Reactor Vessel Material Surveillance (B.2.1.20) program requires that withdrawn but untested surveillance capsules be placed in storage for future re-insertion. The Neutron Fluence Monitoring (B.3.1.2) program will be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the time-limited aging analyses (TLAAs) that evaluate loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel.

3. *Reduction in Fracture Toughness is a plant-specific 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.*

   Table 3.1.1 Item Number 3.1.1-015: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

1. *Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) could occur in stainless steel (SS) and nickel alloy reactor vessel (RV) flange leak detection lines of BWR light-water reactor facilities. The plant-specific operating experience (OE) and condition of the RV flange leak detection lines are evaluated to determine if SCC or IGSCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC or IGSCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   Table 3.1.1 Item Number 3.1.1-016: This item evaluates cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) in stainless steel and nickel alloy reactor vessel flange leak detection lines exposed to air-indoor uncontrolled environments. The reactor vessel flange leak detection lines are stainless steel. Plant-specific OE associated with the stainless steel piping and piping components, including the reactor vessel flange leak detection lines, has been evaluated to determine if cracking due to SCC or IGSCC has occurred. Cracking due to SCC or IGSCC has not been identified as an aging effect at PBAPS for the stainless steel piping and piping components including the reactor vessel flange leak detection lines exposed to air-indoor uncontrolled environments. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in stainless steel reactor vessel flange leak detection lines. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

2. *Cracking due to SCC and IGSCC could occur in SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate SCC and on ASME Code Section XI ISI to detect cracking. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   Table 3.1.1 Item Number 3.1.1-017: This item is not used since the PBAPS BWR design does not include 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. Tor CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI[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).

Table 3.1.1 Item Number 3.1.1-018: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

1. *Cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is recommended to ensure that*

[1]Refer to the GALL-SLR Report, Chapter I, for applicability of other editions of the ASME Code, Section XI.

these aging effects are adequately managed. A plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.1.1 Item Number 3.1.1-019: This item is applicable to PWRs only, and therefore is not used for PBAPS.

2. *Cracking due to SCC could occur in Class 1 PWR cast austenitic stainless steel (CASS) reactor coolant system piping and piping components exposed to reactor coolant. The existing program relies on control of water chemistry to mitigate SCC; however, SCC could occur in CASS components that do not meet the NUREG–0313, "Technical Report on Material Selection and Process Guidelines for BWR Coolant Pressure Boundary Piping" guidelines with regard to ferrite and carbon content. Further evaluation is recommended of a plant-specific program for these components to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   Table 3.1.1 Item Number 3.1.1-020: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3. *Cracking due to SCC could occur in SS or nickel alloy RV flange leak detection lines of PWR light-water reactor facilities. The plant-specific OE and condition of the RV flange leak detection lines are evaluated to determine if SCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.*

   Table 3.1.1 Item Number 3.1.1-139: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.7 Cracking Due to Cyclic Loading

Cracking due to cyclic loading could occur in steel and SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Code Section XI ISI. However, the existing program should be augmented to detect cracking due to cyclic loading. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.1.1 Item Number 3.1.1-021: This item is not used since the PBAPS BWR design does not include an isolation condenser.

3.1.2.2.8 Loss of Material Due to Erosion

Loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. Further evaluation is recommended of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.1.1 Item Number 3.1.1-022: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.9 Aging Management of Pressurized Water Reactor Vessel Internals (Applicable to Subsequent License Renewal Periods Only)

Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)" (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12017A191 through ML12017A197 and ML12017A199), provides the industry's current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. In this report, the EPRI Materials Reliability Program (MRP) identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) SCC, (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth, or (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011 (ADAMS Accession No. ML11308A770), which includes those plant-specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W-designed and Combustion Engineering (CE)-designed RVI components into these inspection categories was based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP has not assessed whether operation of Westinghouse-designed, B&W-designed and CE-designed reactors during an SLR operating period would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227-A or its applicable MRP background documents (e.g., MRP-191 for Westinghouse-designed or CE-designed RVI components or MRP-189 for B&W-designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227-A based AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for *identifying and justifying any potential changes to the MRP-227-A based program that may be necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A.*

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. The NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section A.1.2.3 of SRP-SLR Appendix A.1.

Table 3.1.1 Item Numbers 3.1.1-028, 3.1.1-051a, 3.1.1-051b, 3.1.1-052a, 3.1.1-052b, 3.1.1-052c, 3.1.1-053a, 3.1.1-053b, 3.1.1-053c, 3.1.1-055a, 3.1.1-055b, 3.1.1-055c, 3.1.1-056a, 3.1.1-056b, 3.1.1-056c, 3.1.1-058a, 3.1.1-058b, 3.1.1-059a, 3.1.1-059b, 3.1.1-059c, 3.1.1-118, and 3.1.1-119: These items are applicable to PWRs only, and therefore are not used for PBAPS.

3.1.2.2.10 Loss of Material Due to Wear

1. *Industry OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see Ref. 29). The CRD head penetration nozzles are also called control rod drive mechanism (CRDM) nozzles or CRDM head adapter tubes. The applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP or analysis (with any necessary inspections) for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. Alternatively, the applicant may perform an analysis with any necessary inspections to confirm that loss of material due to wear does not affect the intended function(s) of these CRD head penetration nozzles, consistent with the current licensing basis (CLB).*

   Table 3.1.1 Item Number 3.1.1-116: This item is applicable to PWRs only, and therefore is not used for PBAPS.

2. *Industry OE indicates that loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles due to the interactions between the nozzle and the thermal sleeve (e.g., where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel as described in Ref. 30). Therefore, the applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.*

   Table 3.1.1 Item Number 3.1.1-117: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

1. *Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (EPRI 3002002850).*

   All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 inches in thickness. For the cracks in the 1.3-inch thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 inches, the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 inches near manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-inch deep.

   Although these instances indicate that the water chemistry program may not be sufficient to manage cracking due to PWSCC in SG divider plate assemblies, analyses by the industry indicate that PWSCC in the divider plate assembly does not pose a structural integrity concern for other steam generator components (e.g., tubesheet and tube-to-tubesheet welds) and does not adversely affect other safety analyses (e.g., analyses supporting tube plugging and repairs, tube repair criteria, and design basis accidents). In addition, the industry analyses indicate that flaws in the divider plate assembly will not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various design basis accidents), or in the event of a loss-of-coolant accident (LOCA).

   Furthermore, additional industry analyses indicate that PWSCC in the divider plate assembly is unlikely to adversely impact adjacent items, such as the tubesheet cladding, tube-to-tubesheet welds, and channel head. Therefore,

   - *For units with divider plate assemblies fabricated of Alloy 690 and Alloy 690 type weld materials, a plant-specific AMP is not necessary.*

   - *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary.*

   - *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator programs) may include a one-time inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the steam generator program). The GALL-SLR Report recommends further evaluation for a plant-specific AMP to confirm the effectiveness of the primary water chemistry and steam generator programs as described in this section. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

Table 3.1.1 Item Number 3.1.1-025: This item is applicable to PWRs only, and therefore is not used for PBAPS.

2. *Cracking due to PWSCC could occur in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. The acceptance criteria for this review are:*

   - *For units with Alloy 600 SG tubes for which an alternate repair criterion such as C*, F*, H*, or W* has been permanently approved for both the hot- and cold-leg side of the steam generator, the weld is no longer part of the reactor coolant pressure boundary and a plant-specific AMP is not necessary;*

   - *For units with Alloy 600 steam generator tubes, if there is no permanently approved alternate repair criteria such as C*, F*, H*, or W*, or permanent approval applies to only either the hot- or cold-leg side of the steam generator, a plant-specific AMP is necessary;*

   - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, a plant-specific AMP is not necessary;*

   - *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, a plant-specific AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary face is in compression as discussed in EPRI 3002002850) are applicable and bounding for the unit, and the applicant will perform general visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) as part of the steam generator program. In lieu of a plant-specific AMP, the applicant may provide a rationale for why a plant-specific AMP is not necessary.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and visual inspections of the steam generator head interior surfaces. Along with the primary water chemistry and steam generator programs, a plant-specific AMP should be evaluated to confirm the effectiveness of the primary water chemistry and steam generator programs in certain circumstances. A plant-specific AMP may include a one-time inspection that is capable of detecting cracking to confirm the absence of PWSCC in the tube-to-tubesheet welds. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

Table 3.1.1 Item Number 3.1.1-025: This item is applicable to PWRs only, and therefore is not used for PBAPS.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

GALL-SLR Report AMP XI.M9, "BWR Vessel Internals," manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience cracking due to IASCC. The existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. However, increases in neutron fluence during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage cracking due to IASCC. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant identifies the components to be inspected and performs supplemental inspections to adequately manage IASCC. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Table 3.1.1 Item Number 3.1.1-029, Item Number 3.1.1-041, and Item Number 3.1.1-103: These items evaluate cracking including irradiated assisted stress corrosion cracking (IASCC) in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant with neutron flux. Due to the increase in neutron fluence during the second period of extended operation, an evaluation was performed to determine if supplemental inspections are necessary in addition to those recommended in the existing BWRVIP guidelines.

PBAPS, Unit 2 and 3 will utilize the BWR Vessel Internals aging management program to manage age-related degradation of stainless steel and nickel alloy reactor vessel internal components and welds that are susceptible to cracking due to IASCC. The PBAPS BWR Vessel Internals aging management program is based on the recommendations provided in GALL-SLR Report AMP XI.M9, "BWR Vessel Internals" and implements the referenced BWRVIP guidelines, as applicable. Supplemental inspections to manage IASCC beyond the current BWRVIP guidance are not necessary based on the following evaluation.

The aging mechanism of IASCC is dependent on accumulated neutron irradiation fluence. IASCC degradation of stainless steel or nickel alloys, including welds is not considered to be plausible until an accumulated neutron irradiation fluence threshold has been has been exceeded. A threshold fluence level for IASCC of 5.0×10^{20} n/cm^2 (E>1 MeV) has been generally accepted and is specified in BWRVIP guidance such as BWRVIP-26-A: BWR Vessel and Internals Project BWR Top Guide Inspection and Flaw Evaluation Guidelines. BWRVIP guidance addresses IASCC through 1) periodic inspection requirements for components using techniques capable of detecting cracking due to SCC and 2) flaw tolerance guidance that considers the effect of neutron fluence on material properties and SCC growth rates.

Although a generic threshold neutron irradiation fluence of $5x10^{20}$ n/cm^2 (E>1 MeV) has been generally accepted for onset of IASCC and used as a screening threshold for IASCC applicability, there is little evidence that accumulation of neutron irradiation fluence beyond this threshold results in increased stress corrosion cracking (SCC) occurrence. Periodic examinations of BWR internals subject to neutron irradiation fluence much greater than the threshold (i.e., core shrouds and top guide assemblies) have been performed for many years. To date, these inspections have not identified clear evidence of SCC initiation associated with increased neutron irradiation fluence. In most cases, newly identified cracking is attributed to application of new or more sensitive NDE technologies or implementation of NDE systems that permit probe delivery to locations previously not accessible.

Regardless of operating experience trends, component locations potentially susceptible to IASCC are in all cases evaluated for significance of failure and if determined necessary, are subject to periodic inspection in accordance with the BWRVIP guideline applicable to the component. BWRVIP inspection requirements are conservatively established based considerations that include fleet performance, flaw tolerance, and redundancy. Inspections methods determined to be adequate to detect tight SCC remain adequate to detect IASCC in regions of increased neutron irradiation fluence.

The primary impact of increased neutron irradiation associated with operation beyond 60 years, is the effect on flaw tolerance evaluations. Flaw tolerance evaluation inputs include material fracture toughness and SCC crack growth rate, both of which can be affected by neutron fluence. Although these evaluation inputs can be affected by accumulated neutron fluence, the methods recommended within existing BWRVIP guidance remain adequate for use by licensees to determine the proper re-inspection interval. The application of fracture mechanics tools for the management of vessel internals is not limited by any specific time period. Further, although increased neutron fluences may potentially affect the reinspection interval allowed, the tools remain valid for use at any fluence anticipated for boiling water reactors.

The following PBAPS Unit 2 and Unit 3 reactor vessel internal components are projected to exceed a neutron irradiation fluence of $5x10^{20}$ n/cm^2 (E>1 MeV) prior to the end of the second period of extended operation; top guide, core shroud, core plate, core plate rim holddown bolts, in-core monitor dry tubes, in-core monitor housing, control rod guide tube housing, and orificed fuel support. The evaluations to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines are provided below.

Top Guide – Current inspection recommendations for the top guide are provided in BWRVIP-26-A: BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines and BWRVIP-183: BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines. Both BWRVIP-26-A and BWRVIP-183 consider IASCC an applicable aging mechanism in the determination of the inspection recommendations. Therefore, supplemental inspections in addition to the existing recommended inspections are not necessary.

Core Shroud – Current inspection recommendations for the core shroud are provided in BWRVIP-76-R1-A: BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines. IASCC is identified as one of the observed mechanisms associated with cracking of core shrouds in the industry. The inspection recommendations provided in BWRVIP-76-R1-A are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material fracture toughness and SCC crack growth rate correlations. Therefore, the higher neutron fluence achieved during the second period of extended operation is addressed as part of the current guidance provided in BWRVIP-76-R1-A. Since the core shroud inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the recommended inspection guidance are not necessary.

Core Plate – Current inspection recommendations for the core plate are provided in BWRVIP-25: BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines. Structural evaluations conducted as part of developing BWRVIP-25, concluded that no examinations are required for the core plate since postulated cracking cannot have an adverse effect on the capability of the core plate to perform its intended function. Supplemental inspections in addition to the guidance provided in BWRVIP-25 are not necessary since cracking of the core plate will not prevent the core plate from performing its intended function.

Core Plate Rim Holddown Bolts – Current inspection recommendations for the core plate rim holddown bolts are provided in BWRVIP-25: BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines. For PBAPS Unit 2 and Unit 3, only the top one inch of the most highly irradiated core plate rim holddown bolts is projected to exceed the $5x10^{20}$ n/cm^2 (E>1 MeV) threshold for IASCC prior to the end of the second period of extended operation. The top one inch of the holddown bolt is not highly stressed or a major loading carrying portion of the holddown bolt due to being above the nut. Therefore, IASCC is not considered to be plausible for the core plate holddown bolts and supplemental inspections to address IASCC are not needed.

In-core Monitor Dry Tubes – Current inspection recommendations for the in-core monitor dry tubes are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. BWRVIP-47-A considered IASCC an applicable aging mechanism in the determination of the inspection recommendations, therefore supplemental inspections in addition to the existing recommended inspections are not necessary.

In-core Monitor Housing – Current inspection recommendations for the in-core monitor housings are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. No inspections of the in-core monitor housings are recommended by BWRVIP-47-A. This recommendation is based on the determination that a failure of an in-core monitor housing does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of IASCC to the applicable aging effects does not change the current conclusions of BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

Control Rod Guide Tube Housing - Current inspection recommendations for the control rod guide tube housing are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. 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 PBAPS during the 1999 to 2010 timeframe and no recordable indications were observed. The industry baseline inspection results are under evaluation to determine if the inspection recommendations in BWRVIP-47-A should be revised. Any new or revised inspection recommendations are required to be implemented in accordance with BWRVIP-94-R2-NP: BWR Vessel and Internals Project, Program Implementation Guide and NEI 03-08, Guideline for the Management of Material Issues.

The upper portions of the control rod guide tube housing, in the area of the core plate, are projected to exceed the fluence threshold for IASCC prior to the end of the second period of extended operation. These portions include welds CRGT-1 and CRGT-2 in high fluence areas.

The BWRVIP-47-A recommended baseline inspection of the CRGT-1 welds consists of a VT-3 visual inspection or verification of the alignment lug during removal and installation of the orificed fuel support. These baseline inspections were completed and no indications were observed. Although re-inspection of CRGT-1 welds is not currently required, the orificed fuel supports are removed and installed during control rod blade replacement activities which occur routinely. Also, the failure of the CRGT-1 weld was determined to have no safety consequence as evaluated in BWRVIP-47-A and BWRVIP-06-R1-A. Based on the verification of the alignment lug during control rod blade replacement activities and no safety consequences associated with a failed alignment lug, supplemental inspections or enhancements to the current BWRVIP guidance for CRGT-1 welds are not necessary.

The BWRVIP-47-A recommended baseline inspection of the CRGT-2 welds consists of an EVT-1 visual inspection. These baseline inspections were completed and no indications were observed. As discussed in BWRVIP-06-R1-A during normal plant operation the control rod guide tube and CRGT-2 welds are under compression and a failure is not expected to prevent control rod movement unless horizontal displacement or buckling was to occur. Significant horizontal displacement or buckling which would prevent control rod movement is not expected unless an event such as a LOCA or seismic event occurs when an undetected weld failure is present. Multiple control rod guide tube failures, which are considered to be a very low probability, would be required to prevent safe shutdown of the plant. Although re-inspection of CRGT-2 welds is not currently required, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities which occur routinely. Any gross failure of the CRGT-2 weld could be detected during this activity. Also, baseline inspection data from multiple sites is currently under evaluation by the BWRVIP to determine future inspection recommendations. Based on no indications being identified during the initial baseline inspections, the CRGT-2 welds being under compression during normal plant operation, the low probability of multiple CRGT-2 welds being failed concurrent with a LOCA or seismic event, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary. Any new or revised inspection recommendations are required to be implemented in accordance with BWRVIP-94-R2-NP and NEI 03-08.

Orificed Fuel Support – Current inspection recommendations for the orificed fuel support are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. No inspections of the orificed fuel support are recommended by BWRVIP-47-A. This recommendation is based on assessments in BWRVIP-47-A and BWRVIP-06-R1-A: BWR Vessel and Internals Project, Safety Assessment of BWR Reactor Internals, which concludes that the orificed fuel support castings are highly resistant to impairment by cracking due to the one-piece fabrication, the fact that cracking has not been observed, and that shutdown could be achieved even if a local failure did occur. The inclusion of IASCC to the applicable aging effects does not change the current conclusions of BWRVIP-47-A and BWRVIP-06-R1-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

As discussed above, specifying supplemental inspections beyond the inspections recommended by the current BWRVIP guidelines is not necessary. The BWRVIP is chartered to review and trend operating experience from the BWR fleet relative to implementation of recommended inspections and revise the recommendations as appropriate in accordance with BWRVIP-94-R2-NP and NEI 03-08. As new or revised inspection recommendations are recommended by the BWRVIP, the recommendations are required to be implemented in accordance with BWRVIP-94-R2-NP and NEI 03-08.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

GALL-SLR Report AMP XI.M9 manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience loss of fracture toughness due to neutron irradiation embrittlement. In addition, CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) can experience loss of fracture toughness due to neutron irradiation or thermal aging embrittlement.

The existing BWRVIP examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. Increases in neutron fluence and thermal embrittlement during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage loss of fracture toughness due to neutron irradiation or thermal aging embrittlement. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant should identify the components to be inspected and perform supplemental inspections to adequately manage loss of fracture toughness. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Table 3.1.1 Item Number 3.1.1-099: This item evaluates loss of fracture toughness due to neutron irradiation or thermal aging embrittlement in stainless steel (including cast austenitic stainless steel (CASS), martensitic stainless steel, and precipitation-hardened (PH) martensitic stainless steel) and nickel alloy (including X-750 alloy) reactor vessel internal components exposed to reactor coolant with neutron flux. Due to the increase in neutron fluence during the second period of extended operation, an evaluation was performed to determine if supplemental inspections are necessary in addition to those recommended in the existing BWRVIP guidelines.

The materials used to construct the PBAPS Unit 2 and 3 reactor vessel internals consist of CASS, wrought austenitic stainless steel, and nickel alloys (including alloy 600 and X-750). Precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) were not used in fabrication of any reactor vessel internal component or repair component for PB Unit 2 and Unit 3.

The CASS reactor vessel internal components consist of the following; jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), jet pump restrainer bracket, core spray sparger elbows, control rod guide tube base, and orificed fuel support castings. The aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement on these CASS components was specifically evaluated in BWRVIP-234: BWR Vessel and Internals Project, Thermal Aging and Neutron Embrittlement Evaluation of Cast Austenitic Stainless Steels for BWR Internals. The BWRVIP-234 evaluation determined that no supplemental (augmented) inspections, beyond those recommendations within the current BWRVIP reports were needed for these components to manage the aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement. The NRC staff accepted this recommendation, as adequately managing loss of fracture toughness due to thermal embrittlement and irradiation embrittlement and any possible combined effects of the two, for components that do not exceed $6x10^{20}$ n/cm^2 (1 dpa) as documented in Final Safety Evaluation of the BWRVIP-234: Thermal Aging Embrittlement Evaluation of Cast Austenitic Stainless Steel for BWR Internals, dated June 22, 2016 (Accession No. ML16096A002). For PBAPS Unit 2 and Unit 3, the only CASS components that are projected to exceed a fluence greater than $6x10^{20}$ n/cm^2 (E>1 MeV) prior to the end of the second period of extended operation are the orificed fuel support castings. Therefore, supplemental inspections or enhancements to the BWRVIP guidance are not necessary for the jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), jet pump restrainer bracket, core spray sparger elbows, and control rod guide tube base.

The orificed fuel support castings were determined to be not susceptible to loss of fracture toughness due to thermal aging embrittlement based on being statically cast using CF-8 low molybdenum material and a delta ferrite content of less than 20 percent. However, the orificed fuel support castings in high fluence areas are projected to exceed the threshold of $6x10^{20}$ n/cm^2 (E>1 MeV) for loss of fracture toughness due to neutron irradiation embrittlement. For loss of fracture toughness to have an effect on a component's intended function there must be a mechanism for crack initiation and propagation. During normal plant operation, the orificed fuel support castings are in compression due to the weight of the fuel assemblies they support, therefore tensile stresses to initiate cracking are not present. The orificed fuel support castings are cast from ferritic – austenitic duplex stainless steel which is highly resistant to intergranular stress corrosion cracking (IGSCC). In addition, hydrogen water chemistry treatment is used to mitigate the potential for IGSCC. An assessment documented in BWRVIP-06-R1-A, Safety Assessment of BWR Reactor Internals, concluded that the orificed fuel support castings are highly resistant to impairment by cracking due to one-piece fabrication. Based on the fact that cracking has not been observed and that shutdown could be achieved even if a local failure did occur, no short-term (or long-term) action is required. Based on the above, supplemental inspections or enhancements to the BWRVIP guidance are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement for the orificed fuel support castings.

Wrought austenitic stainless steel and nickel alloy can experience loss of fracture toughness due to neutron embrittlement when exposure to high neutron fluence. Per MRP-175, Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values, the aging effect of loss of fracture toughness due to neutron irradiation embrittlement is applicable for components if the fluence exceeds $1x10^{21}$ n/cm^2 (E>1 MeV) for wrought austenitic stainless steel and $6.7x10^{20}$ n/cm^2 (E>1 MeV) for welded austenitic stainless steel. MRP-175 also specifies that the austenitic stainless steel criterion should be used to nickel alloys. Although this criterion was developed for PWRs, it is considered applicable for boiling water reactors. However, the impact of loss of fracture toughness is only significant if cracking occurs. Conservatively, the threshold for irradiation-assisted stress corrosion cracking (IASCC) of $5x10^{20}$ n/cm2 (E>1 MeV) is applied as a reasonable lower bound fluence for consideration of loss of fracture toughness due to irradiation embrittlement.The wrought austenitic stainless steel reactor internal components and welds that are projected to exceed the fluence threshold for susceptibility to loss of fracture toughness due to neutron irradiation embrittlement ($5x10^{20}$ n/cm^2 (E>1 MeV)) are the top guide, core shroud, core plate, in-core monitor dry tubes, in-core monitor housing, and control rod guide tube housing.

Top Guide – The top guide is currently inspected periodically for cracking. Therefore the aging effect of loss of fracture toughness due to neutron embrittlement can be indirectly managed by identifying aging degradation, implementing early corrective actions, and monitoring and trending age-related degradation. Current inspection recommendations for the top guide are provided in BWRVIP-26-A: BWR Vessel and Internals Project, Top Guide Inspection and Flaw Evaluation Guidelines and BWR-183: BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines. The inspection recommendations provided in BWRVIP-26-A and BWRVIP-183 are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material toughness and crack growth rate correlations. Since the top guide inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the current recommended inspection guidance are not necessary since the higher neutron fluence achieved during the second period of extended operation is addressed as part of the current guidance provide in BWRVIP-26-A and BWRVIP-183.

Core Shroud – The core shroud is currently inspected periodically for cracking. Therefore the aging effect of loss of fracture toughness due to neutron embrittlement can be indirectly managed by identifying aging degradation, implementing early corrective actions, and monitoring and trending age-related degradation. Current inspection recommendations for the core shroud are provided in BWRVIP-76-R1-A: BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines. The inspection recommendations provided in BWRVIP-76-R1-A are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material toughness and crack growth rate correlations. Since the core shroud inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the current recommended inspection guidance are not necessary since the higher neutron fluence achieved during the second period of extended operation is addressed as part of the current guidance provide in BWRVIP-76-R1-A.

Core Plate – Current inspection recommendations for the core plate are provided in BWRVIP-25: BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines. Structural evaluations conducted as part of developing BWRVIP-25, conclude that no examinations are required for the core plate since postulated cracking cannot have an adverse effect on the capability of the core plate to perform its intended function. Supplemental inspections in addition to the guidance provided in BWRVIP-25 are not necessary since cracking of the core plate does not prevent the core plate from performing its intended function.

In-core Monitor Dry Tubes – Current inspection recommendations for the in-core monitor dry tubes are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. No inspections of the in-core monitor dry tubes are recommended by BWRVIP-47-A. This recommendation is based on the determination that a failure of a dry tube does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of loss of fracture toughness to the applicable aging effects does not change the current conclusions of BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

In-core Monitor Housing – Current inspection recommendations for the in-core monitor housings are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. No inspections of the in-core monitor housings are recommended by BWRVIP-47-A. This recommendation is based on the determination that a failure of an in-core monitor housing does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of loss of fracture toughness to the applicable aging effects does not change the current conclusions of BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

Control Rod Guide Tube Housing – Current inspection recommendations for the control rod guide tube housing are provided in BWRVIP-47-A: BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. 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 PBAPS during the 1999 to 2010 timeframe and no recordable indications were observed. The industry baseline inspection results are under evaluation and future inspection recommendations are pending. Any new or revised inspection recommendations are required to be implemented in accordance with BWRVIP-94-R2-NP: BWR Vessel and Internals Project, Program Implementation Guide and NEI 03-08, Guideline for the Management of Material Issues.

The upper portions of the control rod guide tube housing, in the area of the core plate, are projected to exceed the fluence threshold for neutron embrittlement. These portions include welds CRGT-1 and CRGT-2 in high fluence areas.

The BWRVIP-47-A recommended baseline inspection of the CRGT-1 welds consists of a VT-3 visual inspection or verification of the alignment lug during removal and installation of the orificed fuel support. These baseline inspections were completed and no indications were observed. Although re-inspection of CRGT-1 welds is not currently required, the orificed fuel supports are removed and installed during control rod blade replacement activities which occur routinely. Also the failure of the CRGT-1 weld was determined to have no safety consequence as evaluated in BWRVIP-47-A and BWRVIP-06-R1-A. Based on the verification of the alignment lug during control rod blade replacement activities and no safety consequences associated with a failed alignment lug, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary.

The BWRVIP-47-A recommended baseline inspection of the CRGT-2 welds consists of an EVT-1 visual inspection. These baseline inspections were completed and no indications were observed. As discussed in BWRVIP-06-R1-A during normal plant operation the control rod guide tube and CRGT-2 welds are under compression and a failure is not expected to prevent control rod movement unless horizontal displacement or buckling was to occur. Significant horizontal displacement or buckling which would prevent control rod movement is not expected unless an event such as a LOCA or seismic event occurs when an undetected weld failure is present. Multiple control rod guide tube failures, which are considered to be a very low probability, would be required to prevent safe shutdown of the plant. Although re-inspection of CRGT-2 welds is not currently required, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities which occur routinely. Any gross failure of the CRGT-2 welds could be detected during this activity. Also, baseline inspection data from multiple sites is currently under evaluation by the BWRVIP to determine future inspection recommendations. Based on no indications being identified during the initial baseline inspections, the CRGT-2 welds being under compression during normal plant operation, the low probability of multiple CRGT-2 welds being failed concurrent with a LOCA or seismic event, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary. Any new or revised inspection recommendations are required to be implemented in accordance with BWRVIP-94-R2-NP and NEI 03-08.

The nickel alloy reactor vessel internal components consist of the following; core shroud support assembly, core shroud access hole covers and bolting, jet pump holddown beams, jet pump repair hardware (e.g., auxiliary wedges, oversized auxiliary wedges, and slip joint clamps) and core spray repair hardware (e.g., clamps). The reactor vessel internal components fabricated from nickel alloy are located in relatively low fluence areas or were installed later in plant life (i.e., repair hardware). The projected fluence of the nickel alloy components at the end of the second period of extended operation is less than $5x10^{20}$ n/cm^2, therefore loss of fracture toughness due to neutron irradiation embrittlement is not considered an applicable aging effect, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

As discussed above, specifying supplemental inspections beyond the inspections recommended by the current BWRVIP guidelines are not necessary. The BWRVIP is chartered to review and trend operating experience from the BWR fleet relative to implementation of recommended inspections and revise the recommendations as appropriate in accordance with BWRVIP-94-R2-NP and NEI 03-08. As new or revised inspection recommendations are recommended by the BWRVIP, they are required to be implemented in accordance with BWRVIP-94-R2-NP and NEI 03-08.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim holddown bolts. The issue is applicable to BWR-designed light water reactors that employ rim holddown bolts as the means for protecting the reactor's core plate from the consequences of lateral movement. The potential for such movement, if left unmanaged, could impact the ability of the reactor to be brought to a safe shutdown condition during an anticipated transient occurrence or during a postulated design-basis accident or seismic event. This issue is not applicable to BWR reactor designs that use wedges as the means of precluding lateral movement of the core plate because the wedges are fixed in place and are not subject to this type of aging effect and mechanism combination.

GALL-SLR Report AMP XI.M9 indicates that the inspections in the BWRVIP topical report, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines (BWRVIP-25)," are used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR designs with core plate rim holddown bolts. However, in previous license renewal applications (LRAs), some applicants have identified that the inspection bases for managing loss of preload in BWRVIP-25 may not be capable of gaining access to the rim holddown bolts or are not sufficient to detect loss of preload on the components. For applicants that have identified this issue in their past LRAs, the applicants either committed to modifying the plant design to install wedges in the core plate designs or to submit an inspection plan, with a supporting core plate rim holddown bolt preload analysis for NRC approval at least 2 years prior to entering into the initial period of extended operation for the facility.

If an existing NRC-approved analysis for the bolts exists in the CLB and conforms to the definition of a TLAA, the applicant should identify the analysis as a TLAA for the SLRA and demonstrate how the analysis is acceptable in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii). Otherwise, if a new analysis will be performed to support an updated augmented inspection basis for the bolts for the subsequent period of extended operation, the NRC staff recommends that a license renewal commitment be placed in the FSAR Supplement for the applicant to submit both the inspection plan and the supporting loss of preload analysis to the NRC staff for approval at least 2 years prior to entering into the subsequent period of extended operation for the facility. If loss of preload in the bolts is managed with an AMP that correlates to GALL-SLR Report AMP XI.M9, the inspection basis in the applicable BWRVIP report is reviewed for continued validity, or else augmented as appropriate.

Table 3.1.1 Item Number 3.1.1-120: This item evaluates loss of preload due to thermal or irradiation-enhanced stress relaxation in stainless steel core plate rim holddown bolts exposed to reactor coolant with neutron flux.

The BWR Vessel Internals (B.2.1.7) program is enhanced to install core plate wedges for PBAPS Units 2 and 3 no later than six months prior to the second period of extended operation, or before the end of the last refueling outage prior to the second period of extended operation, whichever occurs later; or, submit an inspection plan for the core plate rim holddown bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation. An additional option for management of loss of preload in core plate holddown bolts is evaluation consistent with an NRC-approved procedure documented in a revision to BWRVIP-25.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Table 3.1.1 Item Number 3.1.1-105: This item evaluates steel piping, piping components exposed to concrete. There are no steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System.

Table 3.1.1 Item Number 3.1.1-115: This item evaluates stainless steel piping, piping components exposed to concrete. There are no stainless steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating *isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating*.

Table 3.1.1 Item Number 3.1.1-136: This item evaluates the loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components exposed to air and condensation. Plant-specific OE associated with stainless steel and nickel alloy piping, piping components in the Reactor Vessel, Internals, and Reactor Coolant System has been evaluated to determine if prolonged exposure to air-indoor uncontrolled or condensation has resulted in loss of material due to pitting or crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for the stainless steel and nickel alloy components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel and nickel alloy piping, piping components exposed to air or condensation in the Reactor Vessel, Internals, and Reactor Coolant System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3.

3.1.2.2.18 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessel, Internals, and Reactor Coolant System components:

- Section 4.2, Reactor Vessel and Internals Neutron Embrittlement Analyses
  - Section 4.2.1.1, Reactor Vessel Neutron Fluence Analyses
  - Section 4.2.1.2, Reactor Vessel Internals Neutron Fluences Analyses
  - Section 4.2.2, Reactor Vessel Upper-Shelf Energy (USE) Analyses
  - Section 4.2.3, Reactor Vessel Adjusted Reference Temperature (ART) Analyses
  - Section 4.2.4, Reactor Vessel Pressure – Temperature (P-T) Limits
  - Section 4.2.5, Reactor Vessel Circumferential Weld Failure Probability Analyses

- Section 4.2.6, Reactor Vessel Axial Weld Failure Probability Analyses
- Section 4.2.7, Reactor Vessel Reflood Thermal Shock Analysis
- Section 4.2.8, Core Shroud Reflood Thermal Shock Analysis
- Section 4.2.9, Core Plate Rim Hold-Down Bolt Loss of Preload Analysis
- Section 4.2.10, Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis
- Section 4.2.11, Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis
- Section 4.2.12, Jet Pump Riser Repair Clamp Loss of Preload Analysis
- Section 4.2.13, Replacement Core Plate Extended Life Plug Irradiation – Enhanced Stress Relaxation Analysis
- Section 4.2.14, First License Renewal Application Core Shroud IASCC and Embrittlement Analysis
- Section 4.2.15, Unit 3 Core Spray Replacement Piping Bolting Loss of Preload Evaluation

- Section 4.3, Metal Fatigue Analyses
  - Section 4.3.2, ASME Section III, Class 1 Fatigue Analyses
  - Section 4.3.3, ASME Section III, Class 1 Fatigue Waivers
  - Section 4.3.4, ASME Section III, Class 2, Class 3, and ANSI B31.1 Allowable Stress Analyses
  - Section 4.3.5, Environmental Fatigue Analyses for RPV and Class 1 Piping
  - Section 4.3.6.1, Generic BWR Fatigue Analyses for Various Reactor Vessel Internal Components
  - Section 4.3.6.2, Generic BWR Fatigue Analyses for the Core Shroud
  - Section 4.3.6.3, Core Shroud Support Fatigue Analysis Reevaluation
  - Section 4.3.6.4, Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis
  - Section 4.3.6.5, Replacement Steam Dryer Stress Report and Fatigue Evaluation
  - Section 4.3.7, High-Energy Line Break (HELB) Analyses Based On Cumulative Fatigue Usage

    - Section 4.3.8, Inservice 60-Year RPV Closure Head Weld Flaw Analyses

- Section 4.7, Other Plant-Specific Analyses

    - Section 4.7.2, Reactor Vessel Main Steam Nozzle Clad Removal Corrosion Allowance

    - Section 4.7.3, Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"

    - Section 4.7.5, Unit 3 Core Spray Replacement Piping Fatigue and Leakage Assessment

3.1.3 CONCLUSION

The Reactor Vessel, Internals, and Reactor Coolant System components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Reactor Vessel, Internals, and Reactor Coolant System components are identified in the summaries in Section 3.1.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessel, Internals, and Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-001	Steel reactor vessel 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	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-002	PWR Only				
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	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-005	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-006	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	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 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	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-008	PWR Only				
3.1.1-009	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-010	PWR Only				
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	Fatigue and cyclic loading are TLAAs; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-012	PWR Only				
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	Loss of fracture toughness due to neutron embrittlement is a TLAA; further evaluation is documented in Subsection 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 Programs	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	Consistent with NUREG-2191. The Neutron Fluence Monitoring (B.3.1.2) program and Reactor Vessel Material Surveillance (B.2.1.20) program will be used to manage loss of fracture toughness of the carbon or low alloy steel with stainless steel cladding reactor vessel shell and welds within the beltline that are exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. See Subsection 3.1.2.2.3.2.
3.1.1-015	PWR Only				
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the stainless steel reactor vessel flange leak detection line, reactor vessel penetrations, nozzles, safe ends and welds, and piping, piping components exposed to air - indoor uncontrolled in the Reactor Pressure Vessel and Internals System. See Subsection 3.1.2.2.4.1.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-017	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	Not Applicable. The PBAPS BWR design does not include an isolation condenser. See Subsection 3.1.2.2.4.2.
3.1.1-018	PWR Only				
3.1.1-019	PWR Only				
3.1.1-020	PWR Only				
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	Not Applicable. The PBAPS BWR design does not include an isolation condenser. See Subsection 3.1.2.2.7.
3.1.1-022	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-023	This Item Number is not used in NUREG-2192.				
3.1.1-024	This Item Number is not used in NUREG-2192.				
3.1.1-025	PWR Only				
3.1.1-026	This Item Number is not used in NUREG-2192.				
3.1.1-027	This Item Number is not used in NUREG-2192.				
3.1.1-028	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-029	Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy core shroud and core plate access hole cover (welded - Unit 2) exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation and Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.12.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-030	Stainless steel, nickel alloy penetration: drain line exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (SCC, IGSCC mechanisms only)	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel penetrations, nozzles, safe ends, welds, and vessel shell components exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. The reactor vessel drain line penetration is carbon steel, therefore cracking is addressed by Item Number 3.1.1-007. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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. The PBAPS BWR design does not include an isolation condenser.
3.1.1-032	PWR Only				

Table 3.1.1	Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System				
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-033	PWR Only				
3.1.1-034	PWR Only				
3.1.1-035	PWR Only				
3.1.1-036	PWR Only				
3.1.1-037	PWR Only				
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.2.1.1) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to treated water >482 F in the Standby Liquid Control System, Primary Containment Isolation System, Residual Heat Removal System, and Reactor Recirculation System.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical, or vibratory loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," AMP XI.M2, "Water Chemistry," and XI.M35, "ASME Code Class 1 Small-Bore Piping"	No	Consistent with NUREG-2191 with exceptions. The ASME Code Class 1 Small-Bore Piping (B.2.1.23) program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon steel and stainless steel Class 1 piping, fittings, and branch connections less than 4" NPS and greater than or equal to 1" NPS exposed to reactor coolant, steam, treated water, and treated water > 140 F in the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-040	PWR Only				
3.1.1-040a	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-041	Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and X-750 alloy core shroud and core plate access hole cover (mechanical - Unit 3) exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation and Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.12.
3.1.1-042	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-043	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	The BWR Vessel Internals (B.2.1.7) program has been substituted for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, and will be used with the Water Chemistry (B.2.1.2) program to manage loss of material of stainless steel, nickel alloy, and X-750 alloy reactor vessel internal components exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-044	PWR Only				
3.1.1-045	PWR Only				
3.1.1-046	PWR Only				
3.1.1-047	PWR Only				
3.1.1-048	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-049	PWR Only				
3.1.1-050	Cast austenitic stainless steel Class 1 piping, piping components (including pump casings and control rod drive pressure housings) exposed to reactor coolant >250 °F (>482 °C)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Consistent with NUREG-2191. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel Class 1 reactor recirculation pump casings exposed to treated water >482 F in the Reactor Recirculation System.
3.1.1-051a	PWR Only				
3.1.1-051b	PWR Only				
3.1.1-052a	PWR Only				
3.1.1-052b	PWR Only				
3.1.1-052c	PWR Only				
3.1.1-053a	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-053b	PWR Only				
3.1.1-053c	PWR Only				
3.1.1-054	PWR Only				
3.1.1-055a	PWR Only				
3.1.1-055b	PWR Only				
3.1.1-055c	PWR Only				
3.1.1-056a	PWR Only				
3.1.1-056b	PWR Only				
3.1.1-056c	PWR Only				
3.1.1-057	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-058a	PWR Only				
3.1.1-058b	PWR Only				
3.1.1-059a	PWR Only				
3.1.1-059b	PWR Only				
3.1.1-059c	PWR Only				
3.1.1-060	Steel piping, piping components exposed to reactor coolant	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel piping, piping components exposed to reactor coolant, steam and treated water in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, and Main Steam System.
3.1.1-061	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-062	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the high strength steel and stainless steel closure bolting exposed to air - indoor uncontrolled in the Core Spray System, Main Steam System, Reactor Core Isolation Cooling System, Reactor Pressure Vessel and Internals System, Reactor Pressure Vessel Instrumentation System, Standby Liquid Control System, High Pressure Coolant Injection System, Primary Containment Isolation System, and Reactor Recirculation System. Exceptions apply to NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-063	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel, high strength low alloy steel, and stainless steel closure bolting exposed to air - indoor uncontrolled in the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam System. Exceptions apply to NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.1.1-064	PWR Only				
3.1.1-065	PWR Only				
3.1.1-066	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-067	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of carbon and low alloy steel, high strength low alloy steel, and stainless steel closure bolting exposed to air - indoor uncontrolled in the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam System. Exceptions apply to NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.1.1-068	PWR Only				
3.1.1-069	PWR Only				
3.1.1-070	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-071	PWR Only				
3.1.1-072	PWR Only				
3.1.1-073	PWR Only				
3.1.1-074	PWR Only				
3.1.1-075	PWR Only				
3.1.1-076	PWR Only				
3.1.1-077	PWR Only				
3.1.1-078	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-079	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of stainless steel reactor coolant pressure boundary piping, piping components exposed to steam and treated water in the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Recirculation System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-080	PWR Only				
3.1.1-081	PWR Only				
3.1.1-082	PWR Only				
3.1.1-083	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-084	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of carbon steel top head nozzles and other reactor vessel nozzles, safe-ends, welds, and vessel internal attachments exposed to reactor coolant in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-085	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel reactor vessel flanges, nozzles, safe ends, vessel shells, heads, internal attachments, and welds exposed to reactor coolant and reactor coolant with neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. The BWR Vessel Internals (B.2.1.7) program has been substituted and will be used to manage loss of material of the stainless steel and nickel alloy reactor vessel penetration components located internal to the reactor vessel exposed to reactor coolant and reactor coolant with neutron flux.
3.1.1-086	PWR Only				
3.1.1-087	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-088	PWR Only				
3.1.1-089	PWR Only				
3.1.1-090	This Item Number is not used in NUREG-2192.				
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 exceptions. The Reactor Head Closure Stud Bolting (B.2.1.3) program will be used to manage cracking and loss of material of the high strength low alloy steel bolting with yield strength of 150 ksi or greater reactor vessel closure flange assembly components exposed to air - indoor uncontrolled in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Reactor Head Closure Stud Bolting (B.2.1.3) program implementation.
3.1.1-092	PWR Only				
3.1.1-093	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-094	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 exceptions. The BWR Vessel ID Attachment Welds (B.2.1.4) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel reactor vessel internal attachments exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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.2.1.1) program will be used to manage cracking of the carbon steel reactor vessel feedwater nozzles exposed to reactor coolant in the Reactor Pressure Vessel and Internals System.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-096	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	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage cracking of the capped carbon or low alloy steel with stainless steel cladding reactor vessel control rod drive return line nozzle exposed to reactor coolant in the Reactor Pressure Vessel and Internals System.
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 exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel piping, piping components greater than or equal to 4 inches NPS, reactor vessel nozzle safe ends, control rod drive return line cap and associated weld exposed to reactor coolant and treated water in the Core Spray System, Primary Containment Isolation System, Residual Heat Removal System, Reactor Pressure Vessel and Internals System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-098	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 exceptions. The BWR Penetrations (B.2.1.6) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel reactor vessel instrumentation penetrations and nozzles exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-099	Stainless steel (including cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel); nickel alloy (including X-750 alloy) reactor internal components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	AMP XI.M9, "BWR Vessel Internals"	Yes	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel, nickel alloy, and stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation. See Subsection 3.1.2.2.13.
3.1.1-100	Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant	Loss of material due to wear	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program will be used to manage loss of material of the stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-101	Stainless steel steam dryers exposed to reactor coolant	Cracking due to flow-induced vibration, SCC, IGSCC; loss of material due to wear	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program will be used to manage cracking and loss of material of the stainless steel reactor vessel internals components: steam dryers exposed to reactor coolant in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation.
3.1.1-102	Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel fuel supports and control rod drive housings exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation and Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-103	Stainless steel, nickel alloy reactor internal components exposed to reactor coolant and neutron flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel bolting, nickel alloy, X-750 alloy, and stainless steel reactor vessel nozzle thermal sleeves and reactor vessel internal components exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation and Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.12.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and X-750 alloy reactor vessel internals components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation and Water Chemistry (B.2.1.2) program implementation.
3.1.1-105	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. See Subsection 3.1.2.2.15.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in the Reactor Vessel, Internals, and Reactor Coolant System.
3.1.1-107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	Consistent with NUREG-2191
3.1.1-108	This Item Number is not used in NUREG-2192.				
3.1.1-109	This Item Number is not used in NUREG-2192.				
3.1.1-110	Metallic piping, piping components exposed to reactor coolant	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel piping, piping components exposed to steam and treated water in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Main Steam System.
3.1.1-111	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1.1-112	This Item Number is not used in NUREG-2192.				
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.2.1.1) program will be used to manage loss of material of the carbon steel reactor vessel external attachments, support skirt, and welds exposed to air - indoor uncontrolled in the Reactor Pressure Vessel and Internals System.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (water chemistry-related or corrosion-related aging effect mechanisms only)	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) program will be used to manage cracking and loss of material of the carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, and stainless steel reactor coolant components defined as ASME Section XI Code Class components exposed to condensation, reactor coolant, steam, and treated water > 140 F in the Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-115	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. See Subsection 3.1.2.2.15.
3.1.1-116	PWR Only				
3.1.1-117	PWR Only				
3.1.1-118	PWR Only				
3.1.1-119	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-120	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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program and TLAA will be used to manage loss of preload of the stainless steel core plate rim holddown bolts exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation. Loss of preload is a TLAA; further evaluation is documented in Subsection 3.1.2.2.14.
3.1.1-121	Stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program will be used to manage loss of preload of the stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals (B.2.1.7) program implementation.
3.1.1-122	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-123	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-124	Steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel flow devices and piping, piping components exposed to air - indoor uncontrolled in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Reactor Pressure Vessel and Internals System, Feedwater System, and Main Steam System. The aging effect of loss of material due to general corrosion does not apply to the carbon steel external surfaces of reactor vessel, nozzle, and safe end components exposed to air - indoor uncontrolled in the Reactor Vessel, Internals, and Reactor Coolant System. During power operation the insulated reactor vessel, nozzles, and safe end components have an external temperature greater than 212 °F and are at a higher temperature than the air - indoor uncontrolled environment. During plant shutdown the RPV components and containment atmosphere temperatures are normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant shutdown and loss of material due to general, pitting, or crevice corrosion does not apply.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-125	PWR Only				
3.1.1-126	This Item Number is not used in NUREG-2192.				
3.1.1-127	PWR Only				
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 exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel reactor vessel nozzle safe ends and welds exposed to reactor coolant in the Reactor Pressure Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-129	Steel and stainless steel piping, piping components exposed to reactor coolant: welded connections between the re-routed control rod drive return line and the inlet piping system that delivers return line flow to the reactor pressure vessel exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Not Applicable. The current PBAPS design does not include re-routed control rod drive return lines to the reactor vessel. The original control rod drive return lines have been capped at the reactor vessel nozzle. Control rod drive flow is returned to the reactor vessel though the control rod drive cooling water lines.
3.1.1-130	This Item Number is not used in NUREG-2192.				
3.1.1-131	This Item Number is not used in NUREG-2192.				
3.1.1-132	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-133	Steel components exposed to treated water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage long-term loss of material of the carbon steel reactor vessel nozzles, safe ends, and welds, piping, piping components, and reactor vessel internal attachments exposed to reactor coolant and treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, Feedwater System, and Main Steam 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 Applicable. The "External Surfaces Monitoring of Mechanical Components" (B.2.1.24) program will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air – indoor uncontrolled as addressed by Item Number 3.3.1-182.
3.1.1-135	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-136	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the nickel alloy and stainless steel reactor vessel penetrations, nozzles, safe ends, and welds, piping, piping components, and heat exchanger components exposed to air - indoor uncontrolled and condensation in the Control Rod Drive System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, and Main Steam System. See Subsection 3.1.2.2.16.
3.1.1-137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
3.1.1-138	This Item Number is not used in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-139	PWR Only				

Table 3.1.2-1

Reactor Pressure Vessel and Internals System

Summary of Aging Management Evaluation

Table 3.1.2-1 Reactor Pressure Vessel and Internals System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					TLAA			H, 11
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-65	3.1.1-095	A
					TLAA			H, 8
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	D
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	B
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	B
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	B
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	B
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
					Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-66	3.1.1-096	A
						IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-412	3.1.1-097	A
					Water Chemistry (B.2.1.2)	IV.A1.R-412	3.1.1-097	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
(N13 Flange Leak-Off) Reactor Vessel Nozzle	Direct Flow	Nickel Alloy	Reactor Coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
(N14 Flange Leak-Off) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant and Neutron Flux	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Reactor Coolant and Neutron Flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Access hole cover (Mechanical - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-95	3.1.1-041	B
					Water Chemistry (B.2.1.2)	IV.B1.R-95	3.1.1-041	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
	Mechanical Closure	X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-95	3.1.1-041	B
					Water Chemistry (B.2.1.2)	IV.B1.R-95	3.1.1-041	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Core Shroud and Core Plate: Access hole cover (Welded - Unit 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-94	3.1.1-029	B
					Water Chemistry (B.2.1.2)	IV.B1.R-94	3.1.1-029	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-92	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-92	3.1.1-103	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-96	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-96	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-93	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-93	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		Stainless Steel Bolting	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-93	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-93	3.1.1-103	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
				Loss of Preload	BWR Vessel Internals (B.2.1.7)	IV.B1.R-420	3.1.1-120	B
					TLAA	IV.B1.R-420	3.1.1-120	A, 3
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.R-417	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, and Diffuser casting)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-219	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Jet Pump Assemblies: Hold-down beam bolts	Mechanical Closure	Stainless Steel Bolting	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
				Loss of Preload	BWR Vessel Internals (B.2.1.7)	IV.B1.R-421	3.1.1-121	B
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold-down beams, and Wedges	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
					BWR Vessel Internals (B.2.1.7)	IV.B1.RP-377	3.1.1-100	B
		X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
					BWR Vessel Internals (B.2.1.7)			H, 7

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Reactor Coolant (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1.1-060	A
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Nickel Alloy Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Reactor Vessel (Shell and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant and Neutron Flux (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Fracture Toughness	Neutron Fluence Monitoring (B.3.1.2)	IV.A1.RP-227	3.1.1-014	A
					Reactor Vessel Material Surveillance (B.2.1.20)	IV.A1.RP-227	3.1.1-014	A
					TLAA	IV.A1.R-62	3.1.1-013	A, 2
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Reactor Vessel (Upper Head)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel (Upper Head)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	B
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-51	3.1.1-091	B
				Cumulative Fatigue Damage	TLAA	IV.A1.RP-201	3.1.1-001	A, 1
				Loss of Material	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-165	3.1.1-091	B
	Pressure Boundary	Carbon or Low Alloy Steel with Nickel Alloy Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 9
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Reactor Vessel External Attachments, Support Skirt, and Welds	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.A1.R-70	3.1.1-004	A, 1

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel External Attachments, Support Skirt, and Welds	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-409	3.1.1-113	A
Reactor Vessel Flange Leak Detection Line	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Carbon Steel	Reactor Coolant	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-50	3.1.1-084	C
					Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1.1-094	A
					Water Chemistry (B.2.1.2)	IV.A1.R-64	3.1.1-094	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
			Reactor Coolant and Neutron Flux	Cracking	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1.1-094	A
					Water Chemistry (B.2.1.2)	IV.A1.R-64	3.1.1-094	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.A1.RP-157	3.1.1-085	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1.1-104	B
					Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1.1-104	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	D
					Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	D

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
				Loss of Preload	TLAA			H, 5
		X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1.1-104	B
					Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1.1-104	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components (Jet Pump Auxiliary Wedges)	Structural Integrity (Attached)	X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1.1-104	B
					Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1.1-104	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
					BWR Vessel Internals (B.2.1.7)			H, 7
				Loss of Preload	TLAA			H, 4
Reactor Vessel Internals Components (Jet Pump Oversized Wedges)	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Jet Pump Oversized Wedges)	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1.1-104	B
					Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1.1-104	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
					BWR Vessel Internals (B.2.1.7)			H, 7
				Loss of Preload	TLAA			H, 4
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	D
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
				Loss of Preload	TLAA			H, 4
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	D
					Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Integrity (Attached)	X-750 alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1.1-104	B
					Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1.1-104	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
				Loss of Preload	TLAA			H, 4
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	B
					Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-220	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	B
					Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-220	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	B
					Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components: Instrumentation	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Gas (Internal)	None	None			G, 10
			Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-422	3.1.1-103	B
						IV.B1.R-105	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-105	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Instrumentation	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
		Stainless Steel	Gas (Internal)	None	None	IV.E.RP-07	3.1.1-107	C
			Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-422	3.1.1-103	B
						IV.B1.R-105	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-105	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components: Steam Dryers	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-155	3.1.1-101	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
					BWR Vessel Internals (B.2.1.7)	IV.B1.RP-155	3.1.1-101	B
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-98	3.1.1-103	B
					Water Chemistry (B.2.1.2)	IV.B1.R-98	3.1.1-103	B
				Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 6
					Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow	Stainless Steel	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1.1-085	E, 6
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	C
			Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 1
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1.1-085	E, 6
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1.1-085	E, 6
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
		Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-422	3.1.1-103	B
					BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
					Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
				Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1.1-099	B
				Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1.1-085	E, 6
					Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	IV.A1.R-61a	3.1.1-016	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

2. The TLAA designation in the Aging Management Program column indicates loss of fracture toughness due to neutron embrittlement of this component is evaluated in Section 4.2.

3. The TLAA designation in the Aging Management Program column indicates that loss of preload of the core plate rim bolts due to high neutron fluence is evaluated in Section 4.2.

4. The TLAA designation in the Aging Management Program column indicates that loss of preload due to thermal or neutron irradiation-enhanced stress relaxation of jet pump repair hardware is evaluated in Section 4.2.

5. The TLAA designation in the Aging Management Program column indicates that loss of preload due to thermal or neutron irradiation-enhanced stress relaxation of Unit 3 core spray repair hardware bolting is evaluated in Section 4.2.

6. The BWR Vessel Internals (B.2.1.7) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.1.2-1 Reactor Pressure Vessel and Internals System (Continued)

Plant Specific Notes: (continued)

7. The BWR Vessel Internals (B.2.1.7) program is used to manage loss of material due to wear of X-750 alloy jet pump wedges.

8. The TLAA designation in the Aging Management Program column indicates that feedwater nozzle cracking is evaluated in Section 4.7.

9. During power operation the insulated reactor vessel, nozzles, and safe end components have an external temperature greater than 212 degrees F and are at a higher temperature than the air-indoor (uncontrolled) environment. During plant shutdown the RPV components and containment atmosphere temperatures are normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant shutdown and loss of material due to general, pitting, or crevice corrosion does not apply.

10. The environment of nitrogen Gas (Internal) and material of nickel is not provided in NUREG-2191. Nickel does not have any aging effects in Gas (Internal) environment.

11. The TLAA designation in the Aging Management Program column indicates that main steam nozzle clad removal corrosion allowance is evaluated in Section 4.7.

Table 3.1.2-2
Reactor Pressure Vessel Instrumentation System
Summary of Aging Management Evaluation

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.E-457	3.2.1-114	A

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-2 Reactor Pressure Vessel Instrumentation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage for this component is evaluated in Section 4.3.

Table 3.1.2-3
Reactor Recirculation System
Summary of Aging Management Evaluation

Table 3.1.2-3 Reactor Recirculation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Throttle	Stainless Steel	Treated Water > 140 F (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D1.EP-103b	3.2.1-007	C
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	C
			Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-93	3.2.1-031	B
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140 F (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-93	3.2.1-031	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-112	3.3.1-020	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hoses	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.C.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-060	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	IV.E.R-453	3.1.1-137	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.C.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.C.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 200 F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1.1-060	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (Lower Bearing Fill Metering Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
Pump Casing (Recirc Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 482 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Recirc Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482 F (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Fracture Toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)	IV.C1.R-52	3.1.1-050	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Tanks (Lower Bearing Oil Additional Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	C
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	C
Tanks (Recirc Pump Motor Upper and Lower Bearing Oil Reservoir)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	C

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Recirc Pump Motor Upper and Lower Bearing Oil Reservoir)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	C
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	IV.E.R-453	3.1.1-137	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 482 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-038	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-3 Reactor Recirculation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage for this component is evaluated in Section 4.3.

Table 3.1.2-4
Fuel Assemblies
Summary of Aging Management Evaluation

Table 3.1.2-4 Fuel Assemblies

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fuel Assembly (short-lived)	Not Applicable	Not Applicable	Not Applicable	None	None			1

Table 3.1.2-4 Fuel Assemblies (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. Fuel Assemblies are subject to replacement in accordance with the Core Reload Process. As such, they are short-lived components and not subject to aging management.

3.2 AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES

3.2.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.2, Engineered Safety Features, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Containment Atmosphere Control and Dilution System (2.3.2.1)
- Core Spray System (2.3.2.2)
- High Pressure Coolant Injection System (2.3.2.3)
- Primary Containment Isolation System (2.3.2.4)
- Reactor Core Isolation Cooling System (2.3.2.5)
- Residual Heat Removal System (2.3.2.6)
- Secondary Containment System (2.3.2.7)
- Standby Gas Treatment System (2.3.2.8)

3.2.2 RESULTS

The following tables summarize the results of the aging management review for Engineered Safety Features.

Table 3.2.2-1 Containment Atmosphere Control and Dilution System - Summary of Aging Management Evaluation

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

Table 3.2.2-3 High Pressure Coolant Injection System - Summary of Aging Management Evaluation

Table 3.2.2-4 Primary Containment Isolation 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 Secondary Containment System - Summary of Aging Management Evaluation

Table 3.2.2-8 Standby Gas Treatment System - Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.2.2.1.1 Containment Atmosphere Control and Dilution System

Materials

The materials of construction for the Containment Atmosphere Control and Dilution System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Glass
- Gray Cast Iron
- Nickel Alloy
- Stainless Steel

Environments

The Containment Atmosphere Control and Dilution System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Condensation
- Gas
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Containment Atmosphere Control and Dilution System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Atmosphere Control and Dilution System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.2.2.1.2 Core Spray System

Materials

The materials of construction for the Core Spray System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel
- Glass
- Gray Cast Iron
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting

Environments

The Core Spray System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Gas
- Lubricating Oil
- Treated Water
- Treated Water > 140 F
- Treated Water > 200 F

- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Core Spray System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Core Spray System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Section XI Inservice Inspection, Subsection IWE (B.2.1.30)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.3 High Pressure Coolant Injection System

Materials

The materials of construction for the High Pressure Coolant Injection System components are:

- Carbon Steel
- Carbon Steel (with internal coating)
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Galvanized Steel
- Glass
- Gray Cast Iron
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting

Environments

The High Pressure Coolant Injection System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Lubricating Oil
- Steam
- Treated Water
- Treated Water > 140 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the High Pressure Coolant Injection System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Long-Term Loss of Material

- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the High Pressure Coolant Injection System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Section XI Inservice Inspection, Subsection IWE (B.2.1.30)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.4 Primary Containment Isolation System

Materials

The materials of construction for the Primary Containment Isolation System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less

- Copper Alloy with Greater Than 15% Zinc
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting

Environments

The Primary Containment Isolation System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Gas
- Treated Water
- Treated Water > 140 F
- Treated Water > 200 F
- Treated Water > 482 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Primary Containment Isolation System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Primary Containment Isolation System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Stress Corrosion Cracking (B.2.1.5)

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.5 Reactor Core Isolation Cooling System

Materials

The materials of construction for the Reactor Core Isolation Cooling System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Galvanized Steel
- Glass
- Gray Cast Iron
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting
- Zinc

Environments

The Reactor Core Isolation Cooling System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Lubricating Oil
- Steam
- Treated Water

- Treated Water > 140 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Reactor Core Isolation Cooling System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Core Isolation Cooling System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Section XI Inservice Inspection, Subsection IWE (B.2.1.30)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.6 Residual Heat Removal System

Materials

The materials of construction for the Residual Heat Removal System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Residual Heat Removal System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Gas
- Treated Water
- Treated Water > 140 F
- Treated Water > 200 F
- Treated Water > 482 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Residual Heat Removal System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Hardening and Loss of Strength

- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Residual Heat Removal System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Section XI Inservice Inspection, Subsection IWE (B.2.1.30)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.7 Secondary Containment System

Materials

The materials of construction for the Secondary Containment System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Galvanized Steel

Environments

The Secondary Containment System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Secondary Containment System components require management:

- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Secondary Containment System components:

- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)

3.2.2.1.8 Standby Gas Treatment System

Materials

The materials of construction for the Standby Gas Treatment System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel
- Glass
- Stainless Steel
- Zinc

Environments

The Standby Gas Treatment System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Concrete
- Condensation
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Standby Gas Treatment System components require management:

- Cracking
- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Standby Gas Treatment System components:

- Buried and Underground Piping and Tanks (B.2.1.28)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.2.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Engineered Safety Features, those programs are addressed in the following subsections.

3.2.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Table 3.2.1 Item Number 3.2.1-001: This item evaluates stainless steel and steel piping, piping components exposed to any environment for cumulative fatigue damage due to fatigue. Cumulative fatigue damage of steel and stainless steel piping, piping components is evaluated and dispositioned as a TLAA for the Control Rod Drive System, Feedwater System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System as discussed in Section 4.3.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor stainless steel (SS) and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific operating experience (OE) and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion, and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function *of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of systems, structures, and components (SSCs), the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one-time inspection would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Table 3.2.1 Item Numbers 3.2.1-004 and 3.2.1-048: These items evaluate loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components, and tanks exposed to air or condensation environments. There are no stainless steel or nickel alloy piping, piping components, or tanks exposed to the air-outdoor or air-indoor controlled environments in the Engineered Safety Features Systems. There are no nickel alloy tanks in the Engineered Safety Features Systems. Plant-specific operating experience (OE) associated with stainless steel and nickel alloy components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled and condensation environments has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for stainless steel or nickel alloy components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection

(B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel piping, piping components, and tanks exposed to air-indoor uncontrolled and condensation environments. The One-Time Inspection (B.2.1.21) program will also be implemented to demonstrate that the aging effect of loss of material is not occurring in nickel alloy piping and piping components exposed to air-indoor uncontrolled and condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-099: Not applicable. There are no stainless steel or nickel alloy tanks exposed to air or condensation in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-106: Not applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-107: This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel or nickel alloy piping, piping components, and tanks exposed to air and condensation environments. There are no insulated nickel alloy piping, piping components, or tanks in the Engineered Safety Features Systems. There are no insulated stainless steel piping, piping components or tanks exposed to air-indoor controlled, air-indoor uncontrolled, or air-outdoor in the Engineered Safety Features Systems. Plant-specific OE associated with insulated stainless steel components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for insulated stainless steel components in this environment, indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in loss of material has not occurred. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in insulated stainless steel piping and piping components exposed to condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-112: Not applicable. There are no stainless steel or nickel alloy underground piping, piping components, or tanks in the Engineered Safety Features Systems.

3.2.2.2.3 Loss of Material Due to General Corrosion and Flow Blockage Due to Fouling

Loss of material due to general corrosion (as applicable) and flow blockage due to fouling for all materials can occur in the spray nozzles and flow orifices in the drywell and suppression chamber spray system exposed to air-indoor uncontrolled. This aging effect and mechanism will apply since the carbon steel piping upstream of the spray nozzles and flow orifices is occasionally wetted, even though the majority of the time this system is in standby. The wetting and drying of these components can accelerate corrosion in the system and lead to flow blockage from an accumulation of corrosion products. Aging effects sufficient to result in a loss of intended function are not anticipated if: (a) the *applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (b) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (c) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (d) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (e) a one-time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one-time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.*

Table 3.2.1 Item Number 3.2.1-006: This item evaluates loss of material due to general, pitting, and crevice corrosion and flow blockage due to fouling of metallic drywell and suppression chamber spray nozzles exposed to air-indoor uncontrolled and condensation environments. The PBAPS Unit 2 and Unit 3 drywell and suppression chamber spray nozzles within the Residual Heat Removal System are copper alloy with greater than 15 percent zinc and are exposed to a condensation internal environment. The Residual Heat Removal System carbon steel piping sections downstream of the inboard primary containment motor operated isolation valves up to the drywell and suppression chamber spray nozzles are normally dry and subject to wetting, but are periodically wetted only during transient or accident conditions that require drywell or suppression chamber spray operation. Loss of material is not an aging effect for copper alloys in a condensation environment. Since the upstream piping is carbon steel, flow blockage due to fouling is an applicable aging effect for the spray nozzles.

When the piping between the drywell spray inboard and outboard primary containment isolation valves is filled with water to support inservice testing of valves, that piping is drained prior to opening the inboard isolation valve to preclude water flow into the downstream piping towards the spray header, and to maintain the piping between the isolation valves and the downstream piping to the spray header dry. During inservice testing of the primary containment isolation valves associated with the suppression chamber spray, the piping configuration and sequence of valve testing precludes the piping downstream of the inboard primary containment isolation valve from being wetted. When the piping between suppression chamber spray inboard and outboard primary containment isolation valves is filled with water to support inservice testing of pumps and valves, any leakage past the inboard primary containment isolation valve during testing drains to the suppression chamber via the spray nozzles due to the piping configuration to maintain the piping downstream of the inboard isolation valve dry.

Plant-specific OE has not revealed loss of material or flow blockage due to fouling of drywell or suppression chamber spray nozzles. Additionally, a verification of air flow through each drywell and suppression chamber spray nozzle is performed every 10 years to satisfy Technical Specification surveillance requirements. Therefore, the One-Time Inspection (B.2.1.21) program will be implemented to manage the aging effects of flow blockage due to fouling for the drywell and suppression chamber spray nozzles. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50^{th} and 60^{th} year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope

Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.2.1 Item Number 3.2.1-007: This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are no stainless steel piping, piping components, or tanks exposed to the air-indoor controlled or air-outdoor environments in the Engineered Safety Features Systems. Plant-specific OE associated with stainless steel components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled and condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for stainless steel components in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in stainless steel heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-080: Not applicable. There are no stainless steel underground piping, piping components, or tanks in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-103: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-108: This item evaluates cracking due to SCC in insulated stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are no insulated stainless steel tanks in the Engineered Safety Features Systems. There are no insulated stainless steel piping or piping components exposed to air-indoor controlled, air-indoor uncontrolled, or air-outdoor environments in the Engineered Safety Features Systems. Plant-specific OE associated with insulated stainless steel components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to the condensation environment has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for insulated stainless steel components in the condensation environment indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC has not occurred. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in insulated stainless steel piping and piping components exposed to condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3

3.2.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

3.2.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant-specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10-year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging *effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner*.

Table 3.2.1 Item Number 3.2.1-066: This item evaluates loss of material due to recurring internal corrosion of metallic piping, piping components, and tanks exposed to raw water and waste water. There are no components exposed to raw water in the Engineered Safety Features Systems. Plant-specific OE associated with loss of material of metallic components in the Engineered Safety Features Systems has been evaluated over the period from 2003 to 2017 to identify instances of loss of material due to recurring internal corrosion in waste water and other internal environments. The OE review identified loss of material due to recurring internal corrosion of the galvanized steel shell side components (drip pans) in the waste water environment within the room unit coolers in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System. Recurring internal corrosion has occurred in these locations due to the accumulation of stagnant condensation in the drip pans due to their drain lines becoming clogged. There were no other components within the Engineered Safety Features Systems where the frequency and severity for loss of material met the thresholds discussed above that would require augmenting the aging management recommendations in the GALL-SLR Report to manage loss of material due to recurring internal corrosion.

The galvanized steel drip pans within the room unit coolers will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program. The visual inspections performed under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are sufficient to identify loss of material prior to loss of intended function. The drip pans are accessible for visual inspection. They function as a pressure boundary to direct the flow of air across the cooling coils and to direct any condensation to drain lines. Within the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program the drip pans from all the room unit coolers will be addressed as one material/environment population. Recurring maintenance tasks will be performed on a five-year frequency to inspect and clean the drain lines if required; and to inspect the drip pans for loss of material and repair as necessary. The frequency of inspection will be evaluated based on whether the drain lines are found clogged and the extent of loss of material of the drip pans. The scope of the inspection will address both the cause and the effect of recurring internal corrosion of these components. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is described in Appendix B.

3.2.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of subsequent license renewal (SLR), acceptance criteria for this further evaluation are being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>Susceptible Material</u>: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of

aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.2.1 Item Number 3.2.1-100: Not applicable. There are no aluminum alloy piping, piping components, or tanks exposed to internal environments of air, condensation, raw water, or waste water in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-101: This item evaluates cracking due to SCC in aluminum alloy piping, piping components, and tanks exposed to air and condensation external environments. There are no aluminum alloy tanks in the Engineered Safety Features Systems. There are no aluminum alloy piping, piping components exposed to the air-indoor controlled, air-outdoor, or condensation external environments in the Engineered Safety Features Systems. The following components in the identified systems are constructed of aluminum alloys that are susceptible or assumed susceptible to SCC.

- Containment Atmospheric Control and Dilution System / Valve Body: Pressure regulating valves associated with the Containment Atmospheric Dilution (CAD) Tank pressure build coil and economizer are constructed of 380 series aluminum alloy that is susceptible to SCC. These valves are not insulated or encapsulated and are located in the Nitrogen Storage Building which is an air-indoor uncontrolled environment. There are no nearby secondary sources of moisture or halides present.

- Primary Containment Isolation System / Valve Body: The hand valves in the nitrogen purge line to the Traversing Incore Probe System indexing mechanism are constructed of unknown aluminum alloy series, and therefore are assumed to be susceptible to SCC. These valves are not insulated or encapsulated and are located in the Reactor Building which is an air-indoor uncontrolled environment. There are no nearby secondary sources of moisture or halides present.

Plant-specific OE associated with aluminum alloy components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled environment has resulted in cracking due to SCC from halide exposure. Cracking has not been identified as an aging effect at PBAPS for aluminum alloy components in this environment, or as a result of transportable halogens, indicating that the air-indoor uncontrolled environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in aluminum alloy piping, piping components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-102: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-109: Not applicable. There are no insulated aluminum alloy piping, piping components, or tanks in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-110: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in the Engineered Safety Features Systems.

3.2.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Table 3.2.1 Item Numbers 3.2.1-055: Carbon steel piping, piping components exposed to concrete in the Standby Gas Treatment System is potentially exposed to groundwater, therefore loss of material is considered to be an applicable aging effect. Loss of material is managed by the Buried and Underground Piping and Tanks (B.2.1.28) program and is addressed by Item Number 3.2.1-052.

Table 3.2.1 Item Number 3.2.1-091: Not applicable. There are no stainless steel piping or piping components exposed to concrete in the Engineered Safety Features systems.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic *introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Table 3.2.1 Item Number 3.2.1-042: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy piping, piping components, and tanks exposed to air or condensation external environments. There are no aluminum alloy tanks in the Engineered Safety Features Systems. There are no aluminum alloy piping or piping components exposed to the air-indoor controlled, air-outdoor, or condensation external environments in the Engineered Safety Features Systems. Plant-specific OE associated with aluminum alloy components in the Engineered Safety Features Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled environment has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for aluminum alloy components in this environment, or as a result of transportable halogens, indicating that this environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in aluminum piping, piping components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-056: Not applicable. There are no aluminum alloy piping, piping components, or tanks exposed to internal air or condensation environments in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-105: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-111: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-119: Not applicable. There are no insulated aluminum alloy piping, piping components, or tanks in the Engineered Safety Features Systems.

Table 3.2.1 Item Number 3.2.1-121: Not applicable. There are no aluminum alloy piping, piping components, or tanks exposed to raw water or waste water in the Engineered Safety Features Systems.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Features components:

Section 4.3.2, ASME Section III, Class 1 Fatigue Analyses

Section 4.3.4, ASME Section III, Class 2, Class 3, and ANSI B31.1 Allowable Stress Analyses

Section 4.3.5, Environmental Fatigue Analyses for RPV and Class 1 Piping

Section 4.6.1, Primary Containment Structures, Penetrations, and Associated Components with Fatigue Analyses

3.2.3 CONCLUSION

The Engineered Safety Features components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features components are identified in the summaries in Section 3.2.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Features components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-001	Stainless steel, steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.2.2.2.1.
3.2.1-002	This Item Number is not used in NUREG-2192.				
3.2.1-003	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the nickel alloy and stainless steel piping, piping components, and tanks exposed to air - indoor uncontrolled and condensation in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Standby Gas Treatment System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. See Subsection 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-005	PWR Only				
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage flow blockage of the copper alloy spray nozzles exposed to condensation in the Residual Heat Removal System. See Subsection 3.2.2.2.3.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-007	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the stainless steel heat exchanger components, piping, piping components, and tanks exposed to air - indoor uncontrolled and condensation in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Standby Gas Treatment System, Reactor Pressure Vessel Instrumentation System, Reactor Pressure Vessel and Internals System, Reactor Recirculation System, and Main Steam System. See Subsection 3.2.2.2.4.
3.2.1-008	PWR Only				
3.2.1-009	PWR Only				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-010	Cast austenitic stainless steel 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	The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program has been substituted and will be used to manage loss of fracture toughness of cast austenitic stainless steel piping, piping components exposed to treated water > 482 F in the Reactor Water Cleanup System.
3.2.1-011	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel piping, piping components exposed to steam and treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System and Residual Heat Removal System.
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	Cracking of high-strength steel closure bolting exposed to air – indoor uncontrolled in the Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, and Reactor Core Isolation Cooling System is addressed by Item Number 3.1.1-062.
3.2.1-013	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-014	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor uncontrolled and air - outdoor in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-015	Metallic closure bolting exposed to any environment, soil underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor uncontrolled, air - outdoor, and treated water in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-016	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to reactor coolant, steam, and treated water in the Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel and Internals System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
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, piping components exposed to treated water or treated borated water in Engineered Safety Features systems.
3.2.1-018	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-019	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer of the stainless steel heat exchanger components exposed to treated water in the Residual Heat Removal System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
3.2.1-020	PWR Only				
3.2.1-021	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-022	Nickel alloy, stainless steel heat exchanger components, piping, piping components, tanks exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel heat exchanger components and piping, piping components exposed to steam and treated water in the Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
3.2.1-023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no steel heat exchanger components or piping, piping components exposed to raw water in Engineered Safety Features systems.
3.2.1-024	PWR Only				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-025	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no stainless steel heat exchanger components exposed to raw water in Engineered Safety Features systems.
3.2.1-026	This Item Number is not used in NUREG-2192.				
3.2.1-027	Stainless steel, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no stainless steel or steel heat exchanger tubes exposed to raw water in Engineered Safety Features systems.
3.2.1-028	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no stainless steel piping, piping components exposed to closed cycle cooling water > 140 F in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-029	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel piping, piping components exposed to closed cycle cooling water in the Primary Containment Isolation System. Exceptions apply to the NUREG-2191 recommendations for the Closed Treated Water Systems (B.2.1.12) program implementation.
3.2.1-030	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no steel heat exchanger components exposed to closed cycle cooling water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-031	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed cycle cooling water in the Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Closed Treated Water Systems (B.2.1.12) program implementation.
3.2.1-032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no copper alloy heat exchanger components or piping, piping components exposed to closed cycle cooling water in Engineered Safety Features systems.
3.2.1-033	Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no copper alloy or stainless steel heat exchanger tubes exposed to closed cycle cooling water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-034	Copper alloy (>15% 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.2.1.22) program will be used to manage loss of material of the copper alloy with greater than 15% zinc heat exchanger components exposed to treated water in the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System.
3.2.1-035	PWR Only				
3.2.1-036	PWR Only				
3.2.1-037	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components exposed to soil in Engineered Safety Features systems.
3.2.1-038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage hardening and loss of strength of elastomer ducting and components exposed to air - indoor uncontrolled in the Standby Gas Treatment System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-039	This Item Number is not used in NUREG-2192.				
3.2.1-040	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron ducting and components, heat exchanger components, piping, piping components, and tanks exposed to air - indoor uncontrolled, and air - outdoor in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Secondary Containment System, Standby Gas Treatment System, and Reactor Recirculation System.
3.2.1-041	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-042	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Containment Atmosphere Control and Dilution System and Primary Containment Isolation System. See Subsection 3.2.2.2.10.
3.2.1-043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage hardening and loss of strength of elastomer ducting and components exposed to condensation in the Standby Gas Treatment System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-044	Steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel piping, piping components or ducting and components exposed to air – indoor uncontrolled internal environment in Engineered Safety Features systems. The applicable internal environment for piping, piping components, and ducting and components in Engineered Safety Features systems is condensation, and is addressed by Item Number 3.2.1-46.
3.2.1-045	PWR Only				
3.2.1-046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel, galvanized steel, and gray cast iron ducting and components, heat exchanger components, piping, piping components, and tanks exposed to condensation in the Containment Atmosphere Control and Dilution System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Secondary Containment System, and Standby Gas Treatment System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-047	PWR Only				
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the stainless steel piping, piping components, and tanks exposed to condensation in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Residual Heat Removal System, and Reactor Recirculation System. See Subsection 3.2.2.2.2.
3.2.1-049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron piping, piping components, and tanks exposed to lubricating oil in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Reactor Recirculation System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-050	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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the copper alloy heat exchanger components and piping, piping components exposed to lubricating oil in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Reactor Recirculation System.
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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger components exposed to lubricating oil in the Core Spray System, High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System.
3.2.1-052	Steel piping, piping components exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage loss of material of the carbon steel piping, piping components exposed to concrete and soil in the Standby Gas Treatment System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no stainless steel or nickel alloy piping, piping components or tanks exposed to soil or concrete in Engineered Safety Features systems.
3.2.1-053a	This Item Number is not used in NUREG-2192.				
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	Cracking due to SCC in stainless steel piping, piping components greater than or equal to 4 NPS exposed to treated water >200 F in the Core Spray System, Primary Containment Isolation System, and Residual Heat Removal System is addressed by Item Number 3.1.1-097.
3.2.1-055	Steel piping, piping components exposed to concrete	None	None	Yes	Carbon steel piping, piping components exposed to concrete in the Standby Gas Treatment System is addressed by Item Number 3.2.1-052. See Subsection 3.2.2.2.9.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-056	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	Not Applicable There are no aluminum piping, piping components, or tanks exposed to internal air or condensation environments in Engineered Safety Features systems. See Subsection 3.2.2.2.10.
3.2.1-057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
3.2.1-058	PWR Only				
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not Applicable. There are no galvanized steel ducting, ducting components, or piping, piping components exposed to air – indoor controlled in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191.
3.2.1-061	This Item Number is not used in NUREG-2192.				
3.2.1-062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in Engineered Safety Features 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.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191.
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.2.1.9) program will be used to manage wall thinning of the carbon steel and stainless steel piping, piping components exposed to steam and treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material due to recurring internal corrosion of the galvanized steel heat exchanger components exposed to waste water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System. See Subsection 3.2.2.2.7.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-067	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Engineered Safety Features 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 steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, or condensation in Engineered Safety Features systems.
3.2.1-069	Insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the insulated carbon steel piping, piping components exposed to condensation in the Containment Atmosphere Control and Dilution System and Primary Containment Isolation System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-070	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 steel, stainless steel, or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water or treated borated water in Engineered Safety Features 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	Not Applicable. There are no insulated copper alloy (>15% Zn or >8% Al) piping, piping components, or tanks exposed to air or condensation in Engineered Safety Features systems.
3.2.1-072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water	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 coatings/linings exposed to closed cycle cooling water, raw water, treated water, or treated borated water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program will be used to manage loss of material of the carbon steel tanks exposed to lubricating oil in the High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program implementation.
3.2.1-074	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components with internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, treated borated water, or waste water in Engineered Safety Features systems.
3.2.1-075	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-076	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the stainless steel closure bolting exposed to treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.
3.2.1-077	This Item Number is not used in NUREG-2192.				
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	Carbon steel piping, piping components exposed to concrete and soil in the Standby Gas Treatment System is addressed by Item Number 3.2.1-052. Cracking due to SCC in steel is not an applicable aging effect/mechanism since the concrete and soil are not carbonate/ bicarbonate environments.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the stainless steel closure bolting exposed to air - indoor uncontrolled in the Primary Containment Isolation System. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.
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	Not Applicable. See Subsection 3.2.2.2.4.
3.2.1-081	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air or condensation in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-082	This Item Number is not used in NUREG-2192.				
3.2.1-083	This Item Number is not used in NUREG-2192.				
3.2.1-084	This Item Number is not used in NUREG-2192.				
3.2.1-085	This Item Number is not used in NUREG-2192.				
3.2.1-086	This Item Number is not used in NUREG-2192.				
3.2.1-087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. The "External Surfaces Monitoring of Mechanical Components" (B.2.1.24) program will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air as addressed by Item Number 3.3.1-182.
3.2.1-088	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-089	This Item Number is not used in NUREG-2192.				
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.2.1.21) program will be used to manage long-term loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to treated water in the Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, Residual Heat Removal System, and Reactor Recirculation System.
3.2.1-091	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. See Subsection 3.2.2.2.9.
3.2.1-092	This Item Number is not used in NUREG-2192.				
3.2.1-093	This Item Number is not used in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-094	This Item Number is not used in NUREG-2192.				
3.2.1-095	This Item Number is not used in NUREG-2192.				
3.2.1-096	Steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel or stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in Engineered Safety Features systems.
3.2.1-097	This Item Number is not used in NUREG-2192.				
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 (>15% Zn or >8% Al) piping, piping components exposed to soil in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-099	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	Not Applicable. See Subsection 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	Not Applicable. See Subsection 3.2.2.2.8.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-101	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Containment Atmosphere Control and Dilution System and Primary Containment Isolation System. See Subsection 3.2.2.2.8.
3.2.1-102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.8.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-103	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	Not Applicable. See Subsection 3.2.2.2.4.
3.2.1-104	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Engineered Safety Features 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	Not Applicable. See Subsection 3.2.2.2.10.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-106	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	Not Applicable. See Subsection 3.2.2.2.2.
3.2.1-107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the insulated stainless steel piping, piping components exposed to condensation in the Containment Atmosphere Control and Dilution System. See Subsection 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-108	Insulated 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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the insulated stainless steel piping, piping components exposed to condensation in the Containment Atmosphere Control and Dilution System. See Subsection 3.2.2.2.4.
3.2.1-109	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.8.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.8.
3.2.1-111	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.10.
3.2.1-112	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-113	This Item Number is not used in NUREG-2192.				
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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel piping, piping components exposed to steam and treated water >140 F in the High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
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 exposed to treated water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-116	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to treated water in Engineered Safety Features 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 exposed to closed cycle cooling water in Engineered Safety Features systems.
3.2.1-118	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, or piping, piping components exposed to closed cycle cooling water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-119	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	Not Applicable. See Subsection 3.2.2.2.10.
3.2.1-120	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to soil or concrete in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-121	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.2.2.2.10.
3.2.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of elastomer ducting components exposed to air - indoor uncontrolled in the Standby Gas Treatment System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-123	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 an air internal environment in Engineered Safety Features systems. The applicable internal environment for elastomer ducting components in the Standby Gas Treatment System is condensation. Loss of material due to wear is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program as shown in Table 3.2.2-8.
3.2.1-124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to air with borated water leakage in Engineered Safety Features systems.
3.2.1-125	Steel closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no steel closure bolting exposed to soil, concrete, or underground in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-126	Titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to pitting, crevice corrosion, MIC (except for titanium; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no titanium, super austenitic piping, piping components, tanks, or closure bolting exposed to soil, concrete, or underground in Engineered Safety Features systems.
3.2.1-127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in Engineered Safety Features 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, piping components exposed to soil or underground in Engineered Safety Features 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 stainless steel tanks exposed to soil or concrete in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-130	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components exposed to lubricating oil in the Core Spray System, High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System.
3.2.1-131	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no aluminum piping, piping components exposed to raw water in Engineered Safety Features systems.
3.2.1-132	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in Engineered Safety Features systems.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-133	Titanium piping, piping components, heat exchanger components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no titanium piping, piping components, or heat exchanger components exposed to raw water in Engineered Safety Features systems.
3.2.1-134	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no polymeric piping, piping components, ducting and components, or seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil in Engineered Safety Features systems.

Table 3.2.2-1
Containment Atmosphere Control and Dilution System
Summary of Aging Management Evaluation

Table 3.2.2-1 Containment Atmosphere Control and Dilution System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
	Throttle	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
Insulated Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-403a	3.2.1-069	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	V.E.E-451b	3.2.1-108	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.E.E-450b	3.2.1-107	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-403a	3.2.1-069	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	V.E.E-451b	3.2.1-108	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.E.E-450b	3.2.1-107	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Condensation (Internal)	None	None	V.F.EP-66	3.2.1-060	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Pump Casing (Drywell/Torus CAC and CAD Sample Pump)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
Rupture Disks	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
	Pressure Relief	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Rupture Disks	Pressure Relief	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Sensor Element	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
Strainer (Element)	Filter	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Tanks (CAD Liquid Nitrogen Storage Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	C
		Stainless Steel	Gas (External)	None	None	V.F.EP-22	3.2.1-063	C
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	C
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.E.E-444b	3.2.1-101	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.E.EP-114b	3.2.1-042	A
			Gas (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A

Table 3.2.2-1 Containment Atmosphere Control and Dilution System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

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

Table 3.2.2-2 Core Spray System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
		Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Throttle	Stainless Steel	Treated Water > 140 F (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.E-473	3.2.1-130	A
					One-Time Inspection (B.2.1.21)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Sheet	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VIII.G.SP-79	3.4.1-044	A
					One-Time Inspection (B.2.1.21)	VIII.G.SP-79	3.4.1-044	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Heat Transfer	Stainless Steel	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-79	3.2.1-051	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-79	3.2.1-051	A
	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VIII.G.SP-79	3.4.1-044	A
					One-Time Inspection (B.2.1.21)	VIII.G.SP-79	3.4.1-044	A
Heat Exchanger - (Core Spray Pump Room Cooler) Fins	Heat Transfer	Aluminum Alloy	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.F1.A-771a	3.3.1-242	A
				None	None	VII.F1.A-788a	3.3.1-254	I, 4

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Core Spray Pump Room Cooler) Fins	Heat Transfer	Aluminum Alloy	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-419	3.3.1-096a	C, 2
Heat Exchanger - (Core Spray Pump Room Cooler) Shell Side Components	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
						V.D2.E-400	3.2.1-066	C
Heat Exchanger - (Core Spray Pump Room Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-419	3.3.1-096a	A, 2
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	V.F.EP-10	3.2.1-057	C
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-060	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Elastomer	Treated Water (External)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.A4.AP-101	3.3.1-085	A
			Treated Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.A4.AP-101	3.3.1-085	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 200 F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (Core Spray Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	C, 3
				Flow Blockage	ASME Section XI, Subsection IWE (B.2.1.30)			H, 5

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	C, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-2 Core Spray System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
2. The Heat Transfer intended function applies only to room coolers 2(3)BE057, 2(3)DE057, 2(3)FE057, 2GE057, and 3HE057.
3. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.6.
4. The room cooler fins are constructed of 3003 aluminum alloy which is not susceptible to stress corrosion cracking.
5. Flow blockage due to fouling in the ECCS suction strainers will be managed by the ASME Section XI, Subsection IWE (B.2.1.30) program which includes periodic inspections for sludge accumulation on the torus floor and ensures that sludge accumulation rate does not exceed the design basis assumptions used for design, fabrication, and testing of the strainers.

Table 3.2.2-3
High Pressure Coolant Injection System
Summary of Aging Management Evaluation

Table 3.2.2-3 High Pressure Coolant Injection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Blower Housing (HPCI Gland Seal Condenser Vacuum Pump)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)			G, 2
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)			G, 3
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
		Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Drip Pan	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	E, 4
Flow Device	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Steam (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Throttle	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Steam (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Throttle	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Throttle	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Gearbox (HPCI Pump Gearbox)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
Heat Exchanger - (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (External)	None	None	V.F.EP-10	3.2.1-057	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
					Selective Leaching (B.2.1.22)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (HPCI Lube Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.E-473	3.2.1-130	A
					One-Time Inspection (B.2.1.21)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (HPCI Lube Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.E-473	3.2.1-130	A
					One-Time Inspection (B.2.1.21)	V.D2.E-473	3.2.1-130	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (HPCI Lube Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (HPCI Lube Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (HPCI Lube Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-78	3.2.1-051	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-78	3.2.1-051	A
			Treated Water (Internal)	Reduction of Heat Transfer	One-Time Inspection (B.2.1.21)	VIII.E.SP-100	3.4.1-018	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-100	3.4.1-018	B
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	C
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
					Selective Leaching (B.2.1.22)	V.D2.EP-37	3.2.1-034	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (HPCI Pump Room Cooler) Shell Side Components	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
						V.D2.E-400	3.2.1-066	C
Heat Exchanger - (HPCI Pump Room Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	V.F.EP-10	3.2.1-057	C
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-060	A
	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Condensation (Internal)	None	None	V.F.EP-66	3.2.1-060	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-07	3.2.1-011	A
			Treated Water (External)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Steam (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
				Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1.1-110	A
						IV.C1.R-23	3.1.1-060	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (HPCI Aux Oil Pump)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
Pump Casing (HPCI Booster Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (HPCI Booster Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Pump Casing (HPCI Gland Seal Condenser Condensate Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
Pump Casing (HPCI Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Pump Casing (HPCI Turbine Driven Oil Pump)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Flow Blockage	ASME Section XI, Subsection IWE (B.2.1.30)			H, 5

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Tanks (HPCI Turbine Lube Oil Reservoir)	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)			G, 2
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)			G, 3
			Lubricating Oil (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	V.D2.E-414	3.2.1-073	B
Turbine Casings (HPCI Turbine)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Turbine Casings (HPCI Turbine)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

2. The aging effect on steel (with internal coating) with an internal environment of condensation includes the loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage. This aging effect is managed by the Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program.

3. The aging effect on steel (with internal coating) with an internal environment of condensation includes the loss of material due to general, pitting, and crevice corrosion. This aging effect is managed by the Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program.

4. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program is substituted to manage loss of material for this component type, material and environment combination.

5. Flow blockage due to fouling in the ECCS suction strainers will be managed by the ASME Section XI, Subsection IWE (B.2.1.30) program which includes periodic inspections for sludge accumulation on the torus floor and ensures that sludge accumulation rate does not exceed the design basis assumptions used for design, fabrication, and testing of the strainers.

Table 3.2.2-4

Primary Containment Isolation System

Summary of Aging Management Evaluation

Table 3.2.2-4 Primary Containment Isolation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	V.E.E-421	3.2.1-079	B
				Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Insulated Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.C.EP-99	3.2.1-029	B
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-403a	3.2.1-069	A
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.C.EP-99	3.2.1-029	B

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-403a	3.2.1-069	A
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.C.EP-99	3.2.1-029	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.C.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-62	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.C.EP-62	3.2.1-016	B
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.C.E-457	3.2.1-114	A
					Water Chemistry (B.2.1.2)	V.C.E-457	3.2.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
		Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 200 F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.C.EP-63	3.2.1-022	B
	Pressure Boundary	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.E.E-444b	3.2.1-101	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.E.EP-114b	3.2.1-042	A
		Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.C.EP-99	3.2.1-029	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.C.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-62	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.C.EP-62	3.2.1-016	B
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.C.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
		Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 482 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-038	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.C.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-4 Primary Containment Isolation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage for this component is evaluated in Section 4.3.

Table 3.2.2-5
Reactor Core Isolation Cooling System
Summary of Aging Management Evaluation

Table 3.2.2-5 Reactor Core Isolation Cooling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Blower Housing (RCIC Barometric Condenser Vacuum Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Throttle	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Gearbox (RCIC Turbine Bearing Cavity)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Gearbox (RCIC Turbine Bearing Cavity)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
Heat Exchanger - (RCIC Lube Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.E-473	3.2.1-130	A
					One-Time Inspection (B.2.1.21)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RCIC Lube Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.E-473	3.2.1-130	A
					One-Time Inspection (B.2.1.21)	V.D2.E-473	3.2.1-130	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RCIC Lube Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RCIC Lube Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-78	3.2.1-051	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-78	3.2.1-051	A
			Treated Water (Internal)	Reduction of Heat Transfer	One-Time Inspection (B.2.1.21)	VIII.E.SP-100	3.4.1-018	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-100	3.4.1-018	B
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	C
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
					Selective Leaching (B.2.1.22)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (RCIC Pump Room Cooler) Shell Side Components	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
						V.D2.E-400	3.2.1-066	C

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RCIC Pump Room Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	V.F.EP-10	3.2.1-057	C
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
Piping elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-07	3.2.1-011	A
			Treated Water (External)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-050	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-050	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E4.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.E4.AP-138	3.3.1-100	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
		Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.A-712	3.3.1-167	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)			G, 2
					One-Time Inspection (B.2.1.21)			G, 2
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1.1-110	A
						IV.C1.R-23	3.1.1-060	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (RCIC Barometric Condenser Condensate Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
Pump Casing (RCIC Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
		Stainless Steel	Treated Water (External)	Flow Blockage	ASME Section XI, Subsection IWE (B.2.1.30)			H, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Tanks (RCIC Barometric Condenser and Vacuum Tank)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
Turbine Casings (RCIC Turbine)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-049	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-049	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-5 Reactor Core Isolation Cooling System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

2. The aging effects for zinc in a lubrication oil environment include loss of material. The One Time Inspection (B.2.1.21) program and the Lubricating Oil Analysis (B.2.1.26) program are used to manage loss of material for this component, material, and environment combination.

3. Flow blockage due to fouling in the ECCS suction strainers will be managed by the ASME Section XI, Subsection IWE (B.2.1.30) program which includes periodic inspections for sludge accumulation on the torus floor and ensures that sludge accumulation rate does not exceed the design basis assumptions used for design, fabrication, and testing of the strainers.

Table 3.2.2-6

Residual Heat Removal System

Summary of Aging Management Evaluation

Table 3.2.2-6 Residual Heat Removal System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
		Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	C
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Treated Water (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.1.21)	V.D2.EP-74	3.2.1-019	A
					Water Chemistry (B.2.1.2)	V.D2.EP-74	3.2.1-019	B
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	C
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	D
Heat Exchanger - (RHR Pump Room Cooler) Fins	Heat Transfer	Aluminum Alloy	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.F1.A-771a	3.3.1-242	A
				None	None	VII.F1.A-788a	3.3.1-254	I, 4
				Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-419	3.3.1-096a	C, 3

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RHR Pump Room Cooler) Shell Side Components	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	C
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
						V.D2.E-400	3.2.1-066	C
Heat Exchanger - (RHR Pump Room Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-419	3.3.1-096a	A, 3
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	V.F.EP-10	3.2.1-057	C
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	C
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	D
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2.1-065	A
						V.D2.E-09	3.2.1-011	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Elastomer	Treated Water (External)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.A4.AP-101	3.3.1-085	A
			Treated Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.A4.AP-101	3.3.1-085	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 200 F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (RHR Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	Flow Blockage	One-Time Inspection (B.2.1.21)	V.D2.EP-113a	3.2.1-006	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	C, 2

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Flow Blockage	ASME Section XI, Subsection IWE (B.2.1.30)			H, 5
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	C, 2
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-046	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.E-434	3.2.1-090	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-61b	3.2.1-048	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-022	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-016	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
		Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-107a	3.2.1-004	A
			Treated Water > 482 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A

Table 3.2.2-6 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482 F (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-038	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.2.2-6 Residual Heat Removal System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage for this component is evaluated in Section 4.3.

2. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage for this component is evaluated in Section 4.6.

3. The Heat Transfer intended function applies only to room coolers 2(3)AE058, 2(3)DE058, 2(3)FE058, and 2(3)GE058.

4. The room cooler fins are constructed of 3003 aluminum alloy which is not susceptible to stress corrosion cracking.

5. Flow blockage due to fouling in the ECCS suction strainers will be managed by the ASME Section XI, Subsection IWE (B.2.1.30) program which includes periodic inspections for sludge accumulation on the torus floor and ensures that sludge accumulation rate does not exceed the design basis assumptions used for design, fabrication, and testing of the strainers.

Table 3.2.2-7

Secondary Containment System

Summary of Aging Management Evaluation

Table 3.2.2-7 Secondary Containment System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	C
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	C
Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-7 Secondary Containment System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A

Table 3.2.2-7 Secondary Containment System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.2.2-8

Standby Gas Treatment System

Summary of Aging Management Evaluation

Table 3.2.2-8 Standby Gas Treatment System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
Ducting and Components	Filter	Galvanized Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	C, 3
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	C
		Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.EP-59	3.2.1-038	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-427	3.2.1-043	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C

Table 3.2.2-8 Standby Gas Treatment System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Ducting and Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	C
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.EP-59	3.2.1-038	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-465	3.2.1-122	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-427	3.2.1-043	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
Piping elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-040	A
			Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	V.E.EP-111	3.2.1-052	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.B.E-27	3.2.1-046	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	V.E.EP-111	3.2.1-052	A

Table 3.2.2-8 Standby Gas Treatment System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.B.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.B.EP-107a	3.2.1-004	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	V.B.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	V.B.EP-107a	3.2.1-004	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
			Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
		Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.A-712	3.3.1-167	A
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)			G, 2

Table 3.2.2-8 Standby Gas Treatment System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

2. The One-Time Inspection (B.2.1.21) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

3. This component is located internal to the ventilation ductwork, and therefore the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the applicable aging effects.

3.3 AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Auxiliary Steam System (2.3.3.1)
- Backup Instrument Nitrogen to ADS System (2.3.3.2)
- Battery and Emergency Switchgear Ventilation System (2.3.3.3)
- Chilled Water System (2.3.3.4)
- Condensate Transfer System (2.3.3.5)
- Control Rod Drive System (2.3.3.6)
- Control Room Ventilation System (2.3.3.7)
- Cranes and Hoists System (2.3.3.8)
- Diesel Generator Building Ventilation System (2.3.3.9)
- Domestic Water System (2.3.3.10)
- Emergency Cooling Water System (2.3.3.11)
- Emergency Diesel Generator System (2.3.3.12)
- Emergency Service Water System (2.3.3.13)
- Fire Protection System (2.3.3.14)
- Fuel Handling System (2.3.3.15)
- Fuel Pool Cooling and Cleanup System (2.3.3.16)
- High Pressure Service Water System (2.3.3.17)
- Offgas and Recombiner System (2.3.3.18)
- Plant Equipment and Floor Drain System (2.3.3.19)
- Post Accident Sampling System (2.3.3.20)
- Process Sampling System (2.3.3.21)
- Pump Structure Ventilation System (2.3.3.22)
- Radiation Monitoring System (2.3.3.23)
- Radwaste System (2.3.3.24)
- Reactor Building Closed Cooling Water System (2.3.3.25)
- Reactor Water Cleanup System (2.3.3.26)

- Refueling Water Storage and Transfer System (2.3.3.27)
- Safety Grade Instrument Gas System (2.3.3.28)
- Service Water System (2.3.3.29)
- Standby Liquid Control System (2.3.3.30)
- Suppression Pool Temperature Monitoring System (2.3.3.31)
- Torus Water Cleanup System (2.3.3.32)
- Torus Water Storage and Transfer System (2.3.3.33)
- Traveling Water Screen System (2.3.3.34)
- Turbine Building Closed Cooling Water System (2.3.3.35)
- Water Treatment System (2.3.3.36)

3.3.2 RESULTS

The following tables summarize the results of the aging management review for Auxiliary Systems.

Table 3.3.2-1 Auxiliary Steam System - Summary of Aging Management Evaluation

Table 3.3.2-2 Backup Instrument Nitrogen to ADS System - Summary of Aging Management Evaluation

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System - Summary of Aging Management Evaluation

Table 3.3.2-4 Chilled Water System - Summary of Aging Management Evaluation

Table 3.3.2-5 Condensate Transfer System - Summary of Aging Management Evaluation

Table 3.3.2-6 Control Rod Drive System - Summary of Aging Management Evaluation

Table 3.3.2-7 Control Room Ventilation System - Summary of Aging Management Evaluation

Table 3.3.2-8 Cranes and Hoists System - Summary of Aging Management Evaluation

Table 3.3.2-9 Diesel Generator Building Ventilation System - Summary of Aging Management Evaluation

Table 3.3.2-10 Domestic Water System - Summary of Aging Management Evaluation

Table 3.3.2-11 Emergency Cooling Water System - Summary of Aging Management Evaluation

Table 3.3.2-12 Emergency Diesel Generator System - Summary of Aging Management

3.3.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.3.2.1.1 Auxiliary Steam System

Materials

The materials of construction for the Auxiliary Steam System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Ductile Iron
- Galvanized Steel
- Glass
- Gray Cast Iron
- Stainless Steel

Environments

The Auxiliary Steam System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Auxiliary Steam System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Auxiliary Steam System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.2 Backup Instrument Nitrogen to ADS System

Materials

The materials of construction for the Backup Instrument Nitrogen to ADS System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Gray Cast Iron
- Stainless Steel

Environments

The Backup Instrument Nitrogen to ADS System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Air - Outdoor
- Gas

Aging Effects Requiring Management

The following aging effects associated with the Backup Instrument Nitrogen to ADS System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Backup Instrument Nitrogen to ADS System components:

- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)

3.3.2.1.3 Battery and Emergency Switchgear Ventilation System

Materials

The materials of construction for the Battery and Emergency Switchgear Ventilation System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel
- Stainless Steel

Environments

The Battery and Emergency Switchgear Ventilation System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Air - Outdoor
- Condensation
- Gas

Aging Effects Requiring Management

The following aging effects associated with the Battery and Emergency Switchgear Ventilation System components require management:

- Cracking
- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Battery and Emergency Switchgear Ventilation System components:

- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.3.2.1.4 Chilled Water System

Materials

The materials of construction for the Chilled Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Galvanized Steel
- Gray Cast Iron

- Stainless Steel

Environments

The Chilled Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Chilled Water System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Chilled Water System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.5 Condensate Transfer System

Materials

The materials of construction for the Condensate Transfer System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less

- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Condensate Transfer System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Condensate Transfer System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Condensate Transfer System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.6 Control Rod Drive System

Materials

The materials of construction for the Control Rod Drive System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Glass
- Stainless Steel

Environments

The Control Rod Drive System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Control Rod Drive System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Control Rod Drive System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.7 Control Room Ventilation System

Materials

The materials of construction for the Control Room Ventilation System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel
- Stainless Steel

Environments

The Control Room Ventilation System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Control Room Ventilation System components require management:

- Cracking
- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Control Room Ventilation System components:

- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.3.2.1.8 Cranes and Hoists System

Materials

The materials of construction for the Cranes and Hoists System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting

Environments

The Cranes and Hoists System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Cranes and Hoists System components require management:

- Cracking
- Cumulative Fatigue Damage
- Deformation
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Cranes and Hoists System components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)
- TLAA

3.3.2.1.9 Diesel Generator Building Ventilation System

Materials

The materials of construction for the Diesel Generator Building Ventilation System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer

- Galvanized Steel

Environments

The Diesel Generator Building Ventilation System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Diesel Generator Building Ventilation System components require management:

- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel Generator Building Ventilation System components:

- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)

3.3.2.1.10 Domestic Water System

Materials

The materials of construction for the Domestic Water System components are:

- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Gray Cast Iron

Environments

The Domestic Water System components are exposed to the following environments:

- Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the Domestic Water System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Domestic Water System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.11 Emergency Cooling Water System

Materials

The materials of construction for the Emergency Cooling Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Emergency Cooling Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete

- Condensation
- Lubricating Oil
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Emergency Cooling Water System components require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Cooling Water System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.22)

3.3.2.1.12 Emergency Diesel Generator System

Materials

The materials of construction for the Emergency Diesel Generator System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer

- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Emergency Diesel Generator System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Closed Cycle Cooling Water
- Closed Cycle Cooling Water > 140 F
- Concrete
- Condensation
- Diesel Exhaust
- Fuel Oil
- Lubricating Oil
- Soil
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Emergency Diesel Generator System components require management:

- Cracking
- Cumulative Fatigue Damage
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Diesel Generator System components:

- Bolting Integrity (B.2.1.10)

- Buried and Underground Piping and Tanks (B.2.1.28)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Fuel Oil Chemistry (B.2.1.19)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA

3.3.2.1.13 Emergency Service Water System

Materials

The materials of construction for the Emergency Service Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Glass
- Gray Cast Iron
- PVC
- Stainless Steel
- Stainless Steel (with Internal Coating)
- Stainless Steel Bolting
- Titanium

Environments

The Emergency Service Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Concrete
- Condensation
- Lubricating Oil

- Raw Water
- Soil
- Treated Water
- Underground

Aging Effects Requiring Management

The following aging effects associated with the Emergency Service Water System components require management:

- Cracking
- Flow Blockage
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Service Water System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.14 Fire Protection System

Materials

The materials of construction for the Fire Protection System components are:

- Aluminum Alloy
- Aluminum Silicate
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cementitious Fireproofing
- Concrete
- Concrete Block
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Copper Alloy with Greater Than 15% Zinc (with Chrome Plating)
- Ductile Iron
- Ductile Iron (with Internal Coating)
- Elastomer
- Galvanized Steel
- Glass
- Gray Cast Iron
- Gray Cast Iron (with Internal Coating)
- Grout
- Stainless Steel
- Subliming Compound with and without Reinforcement

Environments

The Fire Protection System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Condensation
- Diesel Exhaust
- Fuel Oil
- Gas

- Lubricating Oil
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Fire Protection System components require management:

- Change in Material Properties
- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Fire Protection System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Fire Protection (B.2.1.16)
- Fire Water System (B.2.1.17)
- Fuel Oil Chemistry (B.2.1.19)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- Lubricating Oil Analysis (B.2.1.26)
- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

- Structures Monitoring (B.2.1.34)
- TLAA

3.3.2.1.15 Fuel Handling System

Materials

The materials of construction for the Fuel Handling System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel
- Stainless Steel Bolting

Environments

The Fuel Handling System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Fuel Handling System components require management:

- Cracking
- Deformation
- Loss of Material
- Loss of Preload

Aging Management Program

The following aging management program manages the aging effects for the Fuel Handling System components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)

3.3.2.1.16 Fuel Pool Cooling and Cleanup System

Materials

The materials of construction for the Fuel Pool Cooling and Cleanup System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Fuel Pool Cooling and Cleanup System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Fuel Pool Cooling and Cleanup System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Pool Cooling and Cleanup System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)

- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.17 High Pressure Service Water System

Materials

The materials of construction for the High Pressure Service Water System components are:

- Carbon Steel
- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Copper Alloy with 15% Zinc or Less
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The High Pressure Service Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Concrete
- Condensation
- Lubricating Oil
- Raw Water
- Soil
- Underground

Aging Effects Requiring Management

The following aging effects associated with the High Pressure Service Water System components require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity

- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the High Pressure Service Water System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.22)

3.3.2.1.18 Offgas and Recombiner System

Materials

The materials of construction for the Offgas and Recombiner System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Glass
- Stainless Steel

Environments

The Offgas and Recombiner System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation

- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Offgas and Recombiner System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Offgas and Recombiner System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.19 Plant Equipment and Floor Drain System

Materials

The materials of construction for the Plant Equipment and Floor Drain System components are:

- Carbon Steel
- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Ductile Iron
- Elastomer

- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Plant Equipment and Floor Drain System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Condensation
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Plant Equipment and Floor Drain System components require management:

- Cracking
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Plant Equipment and Floor Drain System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.20 Post Accident Sampling System

Materials

The materials of construction for the Post Accident Sampling System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Post Accident Sampling System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Post Accident Sampling System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Post Accident Sampling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)

- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.21 Process Sampling System

Materials

The materials of construction for the Process Sampling System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- PVC
- Stainless Steel
- Titanium

Environments

The Process Sampling System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Raw Water
- Treated Water
- Treated Water > 140 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Process Sampling System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Process Sampling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.22 Pump Structure Ventilation System

Materials

The materials of construction for the Pump Structure Ventilation System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Galvanized Steel

Environments

The Pump Structure Ventilation System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Pump Structure Ventilation System components require management:

- Hardening and Loss of Strength
- Loss of Material

- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Pump Structure Ventilation System components:

- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)

3.3.2.1.23 Radiation Monitoring System

Materials

The materials of construction for the Radiation Monitoring System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Radiation Monitoring System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the Radiation Monitoring System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Radiation Monitoring System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)

3.3.2.1.24 Radwaste System

Materials

The materials of construction for the Radwaste System components are:

- Carbon Steel
- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environments

The Radwaste System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Raw Water
- Treated Water
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Radwaste System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Radwaste System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.25 Reactor Building Closed Cooling Water System

Materials

The materials of construction for the Reactor Building Closed Cooling Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- Stainless Steel

Environments

The Reactor Building Closed Cooling Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Reactor Building Closed Cooling Water System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building Closed Cooling Water System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.26 Reactor Water Cleanup System

Materials

The materials of construction for the Reactor Water Cleanup System components are:

- Carbon Steel
- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less
- Glass

- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Water Cleanup System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Treated Water
- Treated Water > 140 F
- Treated Water > 200 F
- Treated Water > 482 F

Aging Effects Requiring Management

The following aging effects associated with the Reactor Water Cleanup System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Water Cleanup System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Reactor Water Cleanup System (B.2.1.15)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

(B.2.1.25)

- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.27 Refueling Water Storage and Transfer System

Materials

The materials of construction for the Refueling Water Storage and Transfer System components are:

- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Gray Cast Iron
- Stainless Steel

Environments

The Refueling Water Storage and Transfer System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Condensation
- Soil
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Refueling Water Storage and Transfer System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Refueling Water Storage and Transfer System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.28 Safety Grade Instrument Gas System

Materials

The materials of construction for the Safety Grade Instrument Gas System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Stainless Steel

Environments

The Safety Grade Instrument Gas System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Gas

Aging Effects Requiring Management

The following aging effects associated with the Safety Grade Instrument Gas System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Safety Grade Instrument Gas System components:

- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- One-Time Inspection (B.2.1.21)

3.3.2.1.29 Service Water System

Materials

The materials of construction for the Service Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Ductile Iron
- Glass
- Gray Cast Iron
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environments

The Service Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Raw Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Service Water System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.30 Standby Liquid Control System

Materials

The materials of construction for the Standby Liquid Control System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon Steel (with Internal Coating)
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Standby Liquid Control System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Lubricating Oil

- Sodium Pentaborate Solution
- Treated Water
- Treated Water > 140 F
- Treated Water > 482 F
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the Standby Liquid Control System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Standby Liquid Control System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.31 Suppression Pool Temperature Monitoring System

Materials

The materials of construction for the Suppression Pool Temperature Monitoring System components are:

- Stainless Steel

Environments

The Suppression Pool Temperature Monitoring System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effect Requiring Management

The following aging effect associated with the Suppression Pool Temperature Monitoring System components requires management:

- Cracking
- Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Suppression Pool Temperature Monitoring System components:

- One-Time Inspection (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.3.2.1.32 Torus Water Cleanup System

Materials

The materials of construction for the Torus Water Cleanup System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Gray Cast Iron
- Stainless Steel

Environments

The Torus Water Cleanup System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Torus Water Cleanup System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Torus Water Cleanup System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.3.2.1.33 Torus Water Storage and Transfer System

Materials

The materials of construction for the Torus Water Storage and Transfer System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Elastomer
- Stainless Steel

Environments

The Torus Water Storage and Transfer System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Torus Water Storage and Transfer System components require management:

- Cracking

- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Torus Water Storage and Transfer System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.3.2.1.34 Traveling Water Screen System

Materials

The materials of construction for the Traveling Water Screen System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Elastomer
- Stainless Steel
- Stainless Steel Bolting

Environments

The Traveling Water Screen System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the Traveling Water Screen System components require management:

- Cracking
- Hardening and Loss of Strength
- Long-Term Loss of Material

- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Traveling Water Screen System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

3.3.2.1.35 Turbine Building Closed Cooling Water System

Materials

The materials of construction for the Turbine Building Closed Cooling Water System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- Stainless Steel

Environments

The Turbine Building Closed Cooling Water System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Lubricating Oil

Aging Effects Requiring Management

The following aging effects associated with the Turbine Building Closed Cooling Water System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building Closed Cooling Water System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)

3.3.2.1.36 Water Treatment System

Materials

The materials of construction for the Water Treatment System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Stainless Steel
- Stainless Steel Bolting

Environments

The Water Treatment System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Water Treatment System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Water Treatment System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.3.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Auxiliary Systems, those programs are addressed in the following subsections.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Table 3.3.1 Item Number 3.3.1-001: This item evaluates steel cranes: rails, bridges, structural members, structural components exposed to the environments of air-indoor uncontrolled and air-outdoor for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is evaluated and dispositioned as a TLAA for the Cranes and Hoists System as discussed in Section 4.7.

Table 3.3.1 Item Number 3.3.1-002: This item evaluates piping, piping components exposed to the environments of diesel exhaust and treated water for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is evaluated and dispositioned as a TLAA for the Auxiliary Steam, Emergency Diesel Generator, Fire Protection, Main

Steam, Offgas and Recombiner, Process Sampling, and Reactor Water Cleanup systems as discussed in Section 4.3.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 °F (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL-SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant-specific operating experience (OE) does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.

Table 3.3.1 Item Numbers 3.3.1-003 and 3.3.1-003a are applicable to PWRs only and are not used for PBAPS.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated, (b) insulated, (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The applicant documents the results of the plant-specific OE review in the license renewal application (LRA).

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.3.1 Item Number 3.3.1-004: This item evaluates cracking due to SCC in stainless steel components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments. There are no stainless steel components exposed to an environment of air-indoor controlled in Auxiliary Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for stainless steel in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of cracking is not occurring in stainless steel heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-094a: Not applicable. There are no stainless steel ducting, ducting components exposed to air, condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-146: Not applicable. There are no stainless steel underground piping, piping components, and tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-205: This item evaluates cracking due to SCC in insulated stainless steel components exposed to air-outdoor and condensation environments. There are no insulated stainless steel components exposed to the environments of air-indoor uncontrolled or air-indoor controlled in Auxiliary Systems. Design specifications for thermal insulation impose limits on leachable concentrations for chlorides and fluorides for insulation used on stainless steel so that SCC is not promoted. Plant OE associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-outdoor and condensation has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for insulated stainless steel in these environments indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC has not occurred. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of cracking is not occurring in insulated stainless steel piping and piping components exposed to air-outdoor and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-231: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Auxiliary Systems.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.2.4 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting *or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Table 3.3.1 Item Number 3.3.1-006: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments. There are no stainless steel components exposed to an environment of air-indoor controlled in Auxiliary Systems. There are no nickel alloy components in the Auxiliary Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for stainless steel in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in stainless steel heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-094: Not applicable. There are no stainless steel ducting, ducting components exposed to air, condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-222: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel tanks exposed to air-indoor uncontrolled and condensation environments. There are no stainless steel tanks exposed to an environment of air-indoor controlled in the Auxiliary Systems. There are no nickel alloy tanks in the Auxiliary Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for stainless steel in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in stainless steel tanks exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-228: Not applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-232: This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel components exposed to air-outdoor and condensation environments. There are no insulated stainless steel components exposed to the environments of air-indoor uncontrolled or air-indoor controlled in Auxiliary Systems. There are no insulated nickel alloy components in the Auxiliary Systems. Design specifications for thermal insulation impose limits on leachable concentrations for chlorides and fluorides for insulation used on stainless steel so that loss of material is not promoted. Plant OE associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-outdoor and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for insulated stainless steel in these environments indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in loss of material has not occurred. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in insulated stainless steel piping and piping components exposed to air-outdoor and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-241: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel heat exchanger components exposed to an air-indoor uncontrolled environment. There are no stainless steel heat exchanger components exposed to the environments of air-indoor controlled, air-outdoor, or condensation in the Auxiliary Systems. There are no nickel alloy heat exchanger components in the Auxiliary Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of air-indoor uncontrolled has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for stainless steel in this environment, or as a result of transportable halogens, indicating that this environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in stainless steel heat exchanger components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-246: Not applicable. There are no stainless steel or nickel alloy underground piping, piping components, and tanks in Auxiliary Systems.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3.

3.3.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, section B.1.4.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component *either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).*

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open-Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water System," or GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Table 3.3.1 Item Number 3.3.1-127: The review of plant specific OE has identified recurring internal corrosion (RIC) in carbon steel piping and piping components exposed to raw water in the Emergency Service Water System, Fire Protection System, High Pressure Service Water System, and Service Water System.

As described below PBAPS will implement the Open-Cycle Cooling Water System (B.2.1.11) program to manage RIC in the Emergency Service Water System, High Pressure Service Water System, and Service Water System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Open-Cycle Cooling Water System (B.2.1.11) program is described in Appendix B.

a) The program utilizes volumetric (e.g., UT) examination methods for the detection of aging effects. These conventional NDE methods quantitatively evaluate components to verify fitness for service and have been proven effective for the detection of aging effects prior to loss of intended function. In addition, in-situ monitoring technologies (e.g., permanent guided wave collars) are used to screen for piping degradation in buried raw water piping, which can then be followed-up with a conventional NDE.

b) The program includes methodology for choosing piping inspection locations and the performance of volumetric inspections for various degradation mechanisms including RIC. The current commitment for GL 89-13 does not include a specified number or location of volumetric examinations. Instead, the number and prioritization of inspection locations is based on the risk associated with specific pipe locations balanced by other factors to investigate and address potential piping integrity concerns. The risk is determined by the combination of piping corrosion susceptibility (based on material, piping size, piping configuration, flow velocity, and past inspection data) and the consequences of pipe leaks or other integrity issues (e.g., piping below minimum required thickness). The size of the inspection scope and criteria used when selecting inspection locations may include: inspections required for extent of condition, inspections required based on the risk factor, re-inspection locations based on Next Scheduled Inspection (NSI) calculations, new inspection locations based on Industry/ Exelon fleet Operating Experience, and follow-up inspections on weld repairs or branch connection/half coupling repairs. The selection of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure is an acceptable approach to address RIC as required by this Further Evaluation. From 2013 through 2017, 150 raw water inspections (141 on safety-related service water systems / 9 on the nonsafety-related service water system) were performed, for an average of 30 per year.

c) The program includes trending of corrosion data and the decision point where increased inspections would be implemented.

- The program includes guidance for the determination of the Next Scheduled Inspection (NSI). This is the calculated time frame at which an inspection will be performed on the measured component based on current measured corrosion rate trending.

- If the cause of the aging effect is not mitigated 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. When the code (e.g., ASME Code Case N-513-3) requires extent of condition (EOC) or scope expansion, the requirements of the code are followed. For EOC inspections that are not driven by code requirements, the Open-Cycle Cooling Water System (B.2.1.11) program is being enhanced to provide for expanding inspection scope. The program will require no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less.

d) Components that are not easily accessed (i.e., buried) are included in the evaluation of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure. In addition to the direct methods of inspection using volumetric examination techniques, indirect methods utilizing guided wave technology are performed. The guided wave inspections provide indications designed to assess inaccessible buried pipes for wall loss, and detects both internal and external corrosion. In many instances, guided wave inspections have been performed coincident with site excavations. When excavations are performed, permanent guided wave collars are typically installed at selected locations to allow for readily available on-demand data. Baseline thickness readings are taken under the guided wave collars prior to installation. Guided wave inspection assessments are qualitative in nature and are utilized to supplement direct volumetric examination data to support corrosion rate inputs in determination of remaining component life.

e) PBAPS is incapable of detecting leaks in buried raw water piping because installed instrumentation is not sensitive enough to detect leakage. However, safety-related service water systems are periodically pressure tested and flow tested to ensure their capability to perform their intended function. Additionally, internal corrosion effects are similar for both buried and accessible piping. PBAPS uses trends on accessible piping locations to inform long-term integrity management decisions for both accessible and buried piping.

As described below, PBAPS will implement the Fire Water System (B.2.1.17) program to manage RIC in the Fire Protection System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Fire Water System (B.2.1.17) program is described in Appendix B.

a) Periodic fire water system piping flushes, flow testing, and ultrasonic inspections are performed to identify pipe degradation prior to loss of system intended function. Periodic ultrasonic inspections were established when RIC was identified (1994) to trend pipe wall thickness in typical piping configurations and locations in high flow areas susceptible to MIC corrosion (horizontal runs, vertical runs, elbows, and piping used for frequent flow testing). The ultrasonic inspections provide representative data for fire water system pipe wall thickness trending and indicates the type of corrosion occurring (localized MIC). This combination of flow tests and inspections is sufficient to detect RIC prior to loss of intended function.

b) Plant OE demonstrates that the currently performed flow testing and ultrasonic testing has provided sufficient data for trending fire water system pipe wall conditions prior to loss of intended function. Identified degraded pipe due to corrosion has been evaluated and replaced when necessary prior to loss of intended function. Additional augmented testing to detect RIC is not required.

c) Parameters trended during piping flushes include flow rates, pressure drops, calculated friction losses and signs of debris from corrosion. Parameters trended during ultrasonic inspections are pipe wall thickness and the area of the degraded condition if identified. When degraded conditions are identified, engineering evaluations are performed to determine the cause. If corrosion is identified, engineering evaluation will determine if additional inspections are required, the appropriate frequency of the inspection based on the projected corrosion rate, extent of condition for other areas in the system, and necessary repairs if required.

d) Underground fire water system piping is ductile iron cement lined pipe. Underground fire main piping was previously inspected in 2014 and found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, tuberculation, or reduction in pipe internal diameter. Future inspections on underground fire main piping will be performed when corrective maintenance work is performed on the fire water underground piping.

e) The fire protection system header pressure is maintained by a connection to the high pressure lube water system. The program includes activities to monitor High Pressure Lube Water Supply Pump operations in lieu of examinations of underground fire main piping. In order to detect indications of fire main leakage, fire protection header pressure, High Pressure Lube Water Supply Pump operation (i.e., pump starts), and High Pressure Lube Water Supply Pump alarms are monitored. If fire protection system header pressure decreases below a pre-established setpoint indicating a leak, the High Pressure Lube Water Supply Pump auto-starts and initiates an alarm in the control room. The alarm prompts operator actions to dispatch operations personnel to determine the cause of the fire protection system header pressure reduction. The combination of continuous monitoring of fire protection system header pressure and the associated High Pressure Lube Water Supply Pump alarm and operator actions are sufficient activities for the identification of leaks in fire water system buried components.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>Susceptible Material</u>: *If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:*

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*

- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, *"External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.3.1 Item Number 3.3.1-186: Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-189: This item evaluates cracking due to SCC in aluminum alloy components exposed to air-indoor uncontrolled and condensation environments. There are no aluminum alloy components exposed to the environments of air-indoor controlled, raw water, or waste water in Auxiliary Systems.

The following component types in the identified systems are exposed to air-indoor uncontrolled or condensation environments but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Radiation Monitoring System / Piping, piping components: Purge air filter housings in the main stack radiation monitor particulate, iodine and gas monitor, and wide range gas detection monitor are constructed of 3003 series aluminum alloy.
- Standby Liquid Control System / Gearbox: Oil level glass bodies located on the Standby Liquid Control System pump gearboxes are constructed of 6063-T6 series aluminum alloy.

The following component types in the identified systems are exposed to air-indoor uncontrolled and are constructed of aluminum alloys that are susceptible to SCC, or assumed susceptible to SCC because the specific series of the aluminum alloy is unknown. Therefore, SCC is a predicted aging effect and aging management of these components for SCC is required.

- Backup Instrument Nitrogen to ADS System / Valve Body: Solenoid valves for the main steam line safety relief valves are constructed of 355-T6 aluminum alloy which is susceptible to SCC. These valves are exposed to a halide free air-indoor uncontrolled environment in the Drywell, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

- Battery and Emergency Switchgear Ventilation System / Valve Body: Various pressure control regulators are constructed of an unknown aluminum alloy series, and therefore are assumed to be susceptible to SCC. These valves are exposed to a halide free air-indoor uncontrolled environment in the ventilation fan area in the Radwaste Building, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

- Emergency Diesel Generator System / Valve Body: Various instrumentation root valves are constructed of 2014 series aluminum alloy which is susceptible to SCC. These valves are exposed to a halide free air-indoor uncontrolled environment in the Diesel Generator Building, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

- Fire Protection System / Odorizer: Cardox System odorizers are constructed of an unknown aluminum alloy series, and therefore are assumed to be susceptible to SCC. These components are exposed to a halide free air-indoor uncontrolled environment in the ECCS rooms in the Reactor Buildings, the Emergency Diesel Generator Building, and the Cable Spreading Room in the Turbine Building and Main Control Room Complex, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

- Fire Protection System / Spray Nozzles: Cardox System hose reel projection nozzles are constructed of an unknown aluminum alloy series, and therefore are assumed to be susceptible to SCC. These components are exposed to a halide free air-indoor uncontrolled environment on the turbine deck of the Unit 2 and Unit 3 Turbine Buildings, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

- Safety Grade Instrument Gas System / Valve Body: Various pressure control valves are constructed of 380 series aluminum alloy which is susceptible to SCC. These valves are exposed to a halide free air-indoor uncontrolled environment in the Reactor Buildings, are not encapsulated in materials containing halides, and are not exposed to secondary sources of moisture or halides.

Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of air-indoor uncontrolled has resulted in cracking due to SCC from halide exposure. Cracking has not been identified as an aging effect at PBAPS for aluminum alloy in this environment, or as a result of exposure to secondary sources, confirming the absence of moisture or halides within the proximity of the aluminum alloy components. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of cracking is not occurring in the aluminum alloy piping and piping components identified above that are susceptible to SCC and exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-192: Not applicable. There are no aluminum underground piping, piping components, and tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-233: Not applicable. There are no insulated aluminum piping, piping components, and tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-254: Not Applicable. There are no aluminum heat exchanger components exposed to air or condensation susceptible to cracking in Auxiliary Systems. However, in Engineered Safety Features Systems, components have been aligned to this Item Number, and include the aluminum alloy Core Spray Pump Room Cooler fins and RHR Room Cooler fins. These flat plate fins are constructed of 3003 series aluminum alloy which is not susceptible to SCC. Therefore, SCC is not a predicted aging effect, and aging management of the room cooler fins for SCC is not required.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and *cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.*

Table 3.3.1 Item Number 3.3.1-112: Loss of material is not considered to be an applicable aging effect for gray cast iron piping, piping components exposed to concrete in the Plant Equipment and Floor Drain System since: (a) attributes of the concrete meet the guidance of American Concrete Institute (ACI) 318 for low water-to-cement ratio, low permeability, and adequate air entrainment; b) plant specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater.

Carbon steel piping, piping components exposed to concrete in the Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, High Pressure Service Water System, and Service Water System are potentially exposed to groundwater and loss of material is considered to be an applicable aging effect. Loss of material is addressed by Item Number 3.3.1-109. This aging effect is managed by the Buried and Underground Piping and Tanks (B.2.1.28) program.

Table 3.3.1 Item Number 3.3.1-202: Not applicable. Stainless steel piping, piping components exposed to concrete in the Refueling Water Storage and Transfer System are potentially exposed to groundwater and loss of material and cracking are considered to be applicable aging effects. The loss of material is addressed by Item Number 3.3.1-107. Cracking is addressed by Item Number 3.3.1-144. These aging effects are managed by the Buried and Underground Piping and Tanks (B.2.1.28) program.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly *that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, “One-Time Inspection,” describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” for tanks; (ii) GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components” for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the “detection of aging effects” program element in GALL-SLR Report AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Table 3.3.1 Item Number 3.3.1-223: Not applicable. There are no aluminum underground piping, piping components, and tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-227: Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-234: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy components exposed to air-indoor uncontrolled and condensation environments. There are no aluminum alloy components exposed to an environment of air-indoor controlled in Auxiliary Systems. All components aligned to this Item Number have been evaluated and assumed to be potentially susceptible to loss of material due to pitting and crevice corrosion as a result of exposure to halides (e.g., chlorides). Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for aluminum alloy in these environments, or as a result of exposure to secondary sources, indicating that the environments do not contain sufficient halides in the presence of moisture to result in loss of material. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in aluminum alloy piping, piping components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-240: Not applicable. There are no aluminum heat exchanger components exposed to waste water in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-242: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy heat exchanger components exposed to a condensation environment. There are no aluminum alloy heat exchanger components exposed to the environments of air-indoor uncontrolled or air-indoor controlled in Auxiliary Systems. All components aligned to this Item Number have been evaluated and assumed to be potentially susceptible to loss of material due to pitting and crevice corrosion as a result of exposure to halides (e.g., chlorides). Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for aluminum alloy heat exchanger components in this environment, or as a result of exposure to secondary sources, indicating that this environment does not contain sufficient halides in the presence of moisture to result in loss of material. Accordingly, PBAPS will implement the One-Time Inspection (B.2.1.21) program to demonstrate that the aging effect of loss of material is not occurring in aluminum alloy heat exchanger components exposed to condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-245: Not applicable. There are no insulated aluminum piping, piping components, and tanks exposed to air and condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-247: Not Applicable. There are no aluminum piping, piping components, and tanks exposed to raw water and waste water in Auxiliary Systems.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Auxiliary Systems components:

Section 4.3.2, ASME Section III, Class 1 Fatigue Analyses

Section 4.3.4, ASME Section III, Class 2, Class 3, and ANSI B31.1 Allowable Stress Analyses

Section 4.7.1, Cranes Cyclic Loading Analysis

3.3.3 CONCLUSION

The Auxiliary Systems components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Auxiliary Systems components are identified in the summaries in Section 3.3.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Auxiliary Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-001	Steel cranes: bridges, structural members, structural components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.7 "Other Plant-Specific TLAAs"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.3.2.2.1.
3.3.1-002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.3.2.2.1.
3.3.1-003	PWR Only				
3.3.1-003a	PWR Only				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-004	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of stainless steel heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Auxiliary Steam, Backup Instrument Nitrogen to ADS, Battery and Emergency Switchgear Ventilation, Chilled Water, Condensate Transfer, Control Rod Drive, Control Room Ventilation, Emergency Cooling Water, Emergency Diesel Generator, Emergency Service Water, Fire Protection, Fuel Pool Cooling and Cleanup, High Pressure Service Water, Offgas and Recombiner, Plant Equipment and Floor Drain, Post Accident Sampling, Process Sampling, Radiation Monitoring, Radwaste, Reactor Building Closed Cooling Water, Reactor Water Cleanup, Refueling Water Storage and Transfer, Safety Grade Instrument Gas, Service Water, Standby Liquid Control, Suppression Pool Temperature Monitoring, Torus Water Cleanup, Torus Water Storage and Transfer, Traveling Water Screen, Turbine Building Closed Cooling Water, and Water Treatment Systems. See Subsection 3.3.2.2.3.
3.3.1-005	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-006	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material in stainless steel heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Auxiliary Steam, Backup Instrument Nitrogen to ADS System, Battery and Emergency Switchgear Ventilation, Chilled Water, Condensate Transfer, Control Rod Drive, Control Room Ventilation, Emergency Cooling Water, Emergency Diesel Generator, Emergency Service Water, Fire Protection, Fuel Pool Cooling and Cleanup, High Pressure Service Water, Offgas and Recombiner, Plant Equipment and Floor Drain, Post Accident Sampling, Process Sampling, Radiation Monitoring, Radwaste, Reactor Building Closed Cooling Water, Reactor Water Cleanup, Refueling Water Storage and Transfer, Safety Grade Instrument Gas, Service Water, Standby Liquid Control, Suppression Pool Temperature Monitoring, Torus Water Cleanup, Torus Water Storage and Transfer, Traveling Water Screen, Turbine Building Closed Cooling Water, and Water Treatment Systems. See Subsection 3.3.2.2.4.
3.3.1-007	PWR Only				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-008	PWR Only				
3.3.1-009	PWR Only				
3.3.1-010	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There are no high-strength steel closure bolting exposed to air, soil, or underground in Auxiliary Systems. Cracking in high-strength steel structural bolting exposed to air-indoor uncontrolled in the Fuel Handling System is addressed by Item Number 3.3.1-199.
3.3.1-011	This Item Number is not used in NUREG-2192.				
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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of carbon and low alloy steel and stainless steel closure bolting exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Auxiliary Steam System, Backup Instrument Nitrogen to ADS System, Chilled Water System, Condensate Transfer System, Control Rod Drive System, Domestic Water System, Emergency Cooling Water System,

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
					Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Process Sampling System, Radiation Monitoring System, Radwaste System, Reactor Building Closed Cooling Water System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Safety Grade Instrument Gas System, Service Water System, Standby Liquid Control System, Torus Water Cleanup System, Torus Water Storage and Transfer System, Traveling Water Screen System, Turbine Building Closed Cooling Water System, and Water Treatment System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.3.1-013	This Item Number is not used in NUREG-2192.				
3.3.1-014	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-015	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of carbon and low alloy steel and stainless steel closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation, raw water, soil, underground, and waste water in the Auxiliary Steam System, Backup Instrument Nitrogen to ADS System, Chilled Water System, Condensate Transfer System, Control Rod Drive System, Domestic Water System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Process Sampling System, Radiation Monitoring System, Radwaste System, Reactor Building Closed Cooling Water System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Safety Grade Instrument Gas System, Service Water System, Standby Liquid Control System, Torus Water Cleanup System, Torus Water Storage and Transfer System, Traveling Water Screen System, Turbine Building Closed Cooling Water System, and Water Treatment System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
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	Consistent with NUREG-2191 with exceptions. The BWR Reactor Water Cleanup System (B.2.1.15) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of stainless steel piping, piping components outboard the second containment isolation valves with a diameter greater than or equal to 4" NPS exposed to treated water > 200 F in the Reactor Water Cleanup System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-017	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 an aging effect of reduction of heat transfer in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-018	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 high-pressure pump casing, piping, piping components, and tanks exposed to treated borated water >60°C (>140°F) or sodium pentaborate solution >60°C (>140°F) in Auxiliary Systems.
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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components exposed to treated water > 140 F in the Reactor Water Cleanup System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-020	Stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F), treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components exposed to treated water > 140 F in the Post Accident Sampling System, Reactor Water Cleanup System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-021	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to sodium pentaborate solution and treated water in the Auxiliary Steam System, Condensate Transfer System, Control Rod Drive System, Fuel Pool Cooling and Cleanup System, Offgas and Recombiner System, Post Accident Sampling System, Process Sampling System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Standby Liquid Control System, Torus Water Cleanup System, and Water Treatment System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-022	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the copper alloy heat exchanger components, piping, piping components exposed to treated water in the Auxiliary Steam System, Condensate Transfer System, Fuel Pool Cooling and Cleanup System, Offgas and Recombiner System, Post Accident Sampling System, Process Sampling System, Reactor Water Cleanup System, Standby Liquid Control System, Water Treatment System, High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-023	This Item Number is not used in NUREG-2192.				
3.3.1-024	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-025	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the aluminum metal components and spent fuel pool gates exposed to treated water in the Reactor Building structure. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage loss of material of the aluminum alloy crane/hoist (Fuel Prep Machine) exposed to treated water in the Fuel Handling System.
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. This component, material, environment, and aging effect combination is addressed by Item Number 3.3.1-203.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-027	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 exposed to treated water with an aging effect /mechanism of reduction of heat transfer due to fouling in Auxiliary Systems.
3.3.1-028	PWR Only				
3.3.1-029	This Item Number is not used in NUREG-2192.				
3.3.1-030	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program has been substituted and will be used to manage cracking, loss of material, and flow blockage of the ceramic tile cooling tower fill exposed to raw water in the Emergency Cooling Tower and Reservoir.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-030a	Fiberglass, 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, HDPE piping, piping components exposed to raw water in Auxiliary Systems.
3.3.1-031	This Item Number is not used in NUREG-2192.				
3.3.1-032	This Item Number is not used in NUREG-2192.				
3.3.1-032a	This Item Number is not used in NUREG-2192.				
3.3.1-033	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the copper alloy piping, piping components, and spray nozzles exposed to raw water in the Emergency Cooling Water System, Process Sampling System, Radiation Monitoring System, and Service Water System. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program has been substituted and will be used to manage loss of material of the copper alloy metal components exposed to raw water in the Circulating Water Pump Structure.
3.3.1-035	This Item Number is not used in NUREG-2192.				
3.3.1-036	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-037	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the carbon steel, ductile iron, and gray cast iron heat exchanger components, piping, piping components exposed to raw water in the Emergency Cooling Water System, Emergency Service Water System, High Pressure Service Water System, Process Sampling System, Radiation Monitoring System, and Service Water System.
3.3.1-038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the carbon steel and copper alloy heat exchanger components exposed to raw water in the Emergency Service Water System, High Pressure Service Water System, and Service Water System.
3.3.1-039	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-040	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.2.1.11) program will be used to manage flow blockage and loss of material of the carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components, piping, piping components, and tanks exposed to raw water in the Emergency Cooling Water System, Emergency Service Water System, High Pressure Service Water System, Radiation Monitoring System, and Service Water System.
3.3.1-041	This Item Number is not used in NUREG-2192.				
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 System (B.2.1.11) program will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger tubes exposed to raw water in the Emergency Service Water System and High Pressure Service Water System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-043	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 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage cracking of stainless steel piping, piping components exposed to closed cycle cooling water > 140 F in the Emergency Diesel Generator System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.
3.3.1-044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage cracking of stainless steel heat exchanger components exposed to closed cycle cooling water > 140 F in the Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-045	Steel piping, piping components, tanks exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to closed cycle cooling water in the Chilled Water System, Emergency Diesel Generator System, Process Sampling System, Reactor Building Closed Cooling Water System, and Turbine Building Closed Cooling Water System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-046	Steel, copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel, copper alloy, and gray cast iron heat exchanger components, piping, piping components exposed to closed cycle cooling water in the Chilled Water System, Emergency Diesel Generator System, Reactor Building Closed Cooling Water System, and Turbine Building Closed Cooling Water System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.
3.3.1-047	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed cycle cooling water in the Post Accident Sampling System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-048	Aluminum piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the aluminum alloy piping, piping components exposed to closed cycle cooling water in the Emergency Diesel Generator System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.
3.3.1-049	Stainless steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel heat exchanger components, piping, piping components exposed to closed cycle cooling water in the Chilled Water System, Emergency Diesel Generator System, and Reactor Building Closed Cooling Water System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage reduction of heat transfer of the copper alloy heat exchanger tubes exposed to closed cycle cooling water in the Emergency Diesel Generator System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation.
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. Boraflex is not used for neutron absorption in the spent fuel storage pool. Boralcan is used and is addressed in Item Number 3.3.1-102.
3.3.1-052	Steel cranes: rails, bridges, structural members, structural components exposed to air	Loss of material due to general corrosion, wear, deformation, cracking	AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program will be used to manage cracking, deformation, and loss of material of the carbon steel crane/hoist and cranes: rails, bridges, structural members, and structural components exposed to air-indoor uncontrolled and air-outdoor in the Cranes and Hoists System and Fuel Handling System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-053	This Item Number is not used in NUREG-2192.				
3.3.1-054	This Item Number is not used in NUREG-2192.				
3.3.1-055	Steel piping, piping components, tanks exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron piping, piping components, and tanks exposed to condensation in the Control Rod Drive System, Emergency Diesel Generator System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Radiation Monitoring System, Reactor Building Closed Cooling Water System, Torus Water Storage and Transfer System, Turbine Building Closed Cooling Water System, and Reactor Recirculation System.
3.3.1-056	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-057	Elastomer fire barrier penetration seals exposed to air, condensation	Hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program will be used to manage hardening and loss of strength of the elastomer fire barriers exposed to air-indoor uncontrolled in the Fire Protection System.
3.3.1-058	Steel halon/carbon dioxide fire suppression system piping, piping components exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron fire barriers, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Fire Protection System.
3.3.1-059	Steel fire rated doors exposed to air	Loss of material due to wear	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program will be used to manage loss of material of the carbon steel fire barrier doors exposed to air-indoor uncontrolled and air-outdoor 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 Programs	Further Evaluation Recommended	Discussion
3.3.1-060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program and Structures Monitoring (B.2.1.34) program will be used to manage cracking and loss of material of the concrete and grout fire barriers and concrete elements exposed to air-indoor uncontrolled and air-outdoor in the Fire Protection System.
3.3.1-061	This Item Number is not used in NUREG-2192.				
3.3.1-062	This Item Number is not used in NUREG-2192.				
3.3.1-063	Steel fire hydrants exposed to air – outdoor, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling (raw water, raw water (potable) only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage flow blockage and loss of material of the ductile iron and gray cast iron fire hydrants exposed to air-outdoor and raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-064	Steel, copper alloy piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to general (steel; copper alloy in raw water and raw water (potable) only), pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water; raw water (potable) for steel only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage flow blockage and loss of material of the carbon steel, copper alloy, ductile iron, ductile iron (with internal coating), galvanized steel, gray cast iron, and gray cast iron (with internal coating) fire hydrants, piping, piping components, piping components with internal coatings, and tanks exposed to raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.
3.3.1-065	Aluminum piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. This component, material, environment, and aging effect combination is addressed in Item Number 3.3.1-025.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-066	Stainless steel piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage flow blockage and loss of material of the stainless steel piping, piping components exposed to raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.
3.3.1-067	This Item Number is not used in NUREG-2192.				
3.3.1-068	This Item Number is not used in NUREG-2192.				
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.2.1.19) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the copper alloy piping, piping components exposed to fuel oil in the Emergency Diesel Generator System and Fire Protection System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-070	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.2.1.19) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the carbon steel and gray cast iron piping, piping components, and tanks exposed to fuel oil and in the Emergency Diesel Generator System and Fire Protection System.
3.3.1-071	Stainless steel, aluminum piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191. The Fuel Oil Chemistry (B.2.1.19) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the aluminum alloy and stainless steel piping, piping components exposed to fuel oil in the Emergency Diesel Generator System and Fire Protection System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching (B.2.1.22) program will be used to manage loss of material of the copper alloy with greater than 15% zinc, ductile iron, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to closed cycle cooling water, raw water, soil, treated water, and waste water in the Auxiliary Steam System, Chilled Water System, Condensate Transfer System, Domestic Water System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Process Sampling System, Radwaste System, Reactor Building Closed Cooling Water System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Residual Heat Removal System, Service Water System, Torus Water Cleanup System, Turbine Building Closed Cooling Water System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Circulating Water Pump Structure, and Emergency Cooling Tower and Reservoir.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-073	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	The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program has been substituted and will be used to manage cracking and loss of material of the ceramic tile cooling tower fill exposed to air-outdoor in the Emergency Cooling Tower and Reservoir.
3.3.1-074	This Item Number is not used in NUREG-2192.				
3.3.1-075	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage hardening and loss of strength of the elastomer ducting, ducting components, piping, piping components exposed to air-indoor uncontrolled in the Battery and Emergency Switchgear Ventilation System, Control Room Ventilation System, Diesel Generator Building Ventilation System, Emergency Diesel Generator System, Emergency Service Water System, Plant Equipment and Floor Drain System, Pump Structure Ventilation System, Torus Water Storage and Transfer System, and Traveling Water Screen System.
3.3.1-077	This Item Number is not used in NUREG-2192.				
3.3.1-078	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron ducting, ducting components, heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Auxiliary Steam System, Backup Instrument Nitrogen to ADS System, Battery and

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					Emergency Switchgear Ventilation System, Chilled Water System, Condensate Transfer System, Control Rod Drive System, Control Room Ventilation System, Diesel Generator Building Ventilation System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Process Sampling System, Pump Structure Ventilation System, Radiation Monitoring System, Radwaste System, Reactor Building Closed Cooling Water System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Service Water System, Standby Liquid Control System, Torus Water Cleanup System, Torus Water Storage and Transfer System, Traveling Water Screen System, Turbine Building Closed Cooling Water System, and Water Treatment System.
3.3.1-079	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-080	Steel heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron heat exchanger components, piping, piping components exposed to air-indoor uncontrolled and air-outdoor in the Auxiliary Steam System, Chilled Water System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Reactor Building Closed Cooling Water System, Reactor Water Cleanup System, Service Water System, and Turbine Building Closed Cooling Water System.
3.3.1-081	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-082	Elastomer, fiberglass piping, piping components, ducting, ducting components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the elastomer piping, piping components exposed to air-indoor uncontrolled in the Battery and Emergency Switchgear Ventilation System, Control Room Ventilation System, Diesel Generator Building Ventilation System, Pump Structure Ventilation System, and Traveling Water Screen System.
3.3.1-083	Stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage cracking of stainless steel piping, piping components exposed to diesel exhaust in the Emergency Diesel Generator System.
3.3.1-084	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-085	Elastomer piping, piping components, seals exposed to air, condensation, closed-cycle cooling water, treated borated water, treated water, raw water, raw water (potable), waste water, gas, fuel oil, lubricating oil	Hardening or loss of strength due to elastomer degradation; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage hardening and loss of strength of the elastomer ducting, ducting components, piping, piping components exposed to closed cycle cooling water, condensation, fuel oil, lubricating oil, raw water, treated water, and waste water in the Battery and Emergency Switchgear Ventilation System, Control Room Ventilation System, Diesel Generator Building Ventilation System, Emergency Diesel Generator System, Emergency Service Water System, Plant Equipment and Floor Drain System, Pump Structure Ventilation System, Torus Water Storage and Transfer System, Traveling Water Screen System, Core Spray System, and Residual Heat Removal System.
3.3.1-086	This Item Number is not used in NUREG-2192.				
3.3.1-087	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-088	Steel; 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.2.1.25) program will be used to manage loss of material of the carbon steel, gray cast iron, and stainless steel, piping, piping components, and tanks exposed to diesel exhaust and raw water in the Domestic Water System, Emergency Diesel Generator System, Fire Protection System, and Radwaste System.
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 exceptions. The Fire Water System (B.2.1.17) program will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron piping, piping components exposed to condensation in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-090	Steel ducting, ducting components (internal surfaces) exposed to condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel and galvanized steel ducting and ducting components exposed to condensation in the Battery and Emergency Switchgear Ventilation System, Chilled Water System, Control Room Ventilation System, Diesel Generator Building Ventilation System, and Pump Structure Ventilation System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-091	Steel piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to waste water in the Chilled Water System, Emergency Diesel Generator System, Plant Equipment and Floor Drain System, Process Sampling System, Radwaste System, Standby Liquid Control System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, and Residual Heat Removal System. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program has been substituted and will be used to manage loss of material of the carbon steel piping, piping components exposed to waste water in the High Pressure Coolant Injection System and Standby Liquid Control System.
3.3.1-092	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the copper alloy piping, piping components exposed to raw water in the Domestic Water System.
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	Not Applicable. There are no stainless steel ducting, ducting components exposed to air or condensation in Auxiliary Systems. See Subsection 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	Not Applicable. There are no stainless steel ducting, ducting components exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.3.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the copper alloy and stainless steel piping, piping components, and tanks exposed to waste water in the Emergency Diesel Generator System, Plant Equipment and Floor Drain System, Process Sampling System, Radwaste System, and Containment Atmosphere Control and Dilution System.
3.3.1-096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the elastomer piping, piping components exposed to raw water in the Traveling Water Screen System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-096a	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.2.1.25) program will be used to manage reduction of heat transfer of the aluminum alloy heat exchanger fins and copper alloy heat exchanger tubes exposed to condensation in the Core Spray System and Residual Heat Removal System.
3.3.1-096b	Steel heat exchanger components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to condensation in the High Pressure Service Water System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted and will be used to manage loss of material of the carbon steel heat exchanger tubes exposed to condensation in the Reactor Building Closed Cooling Water System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-097	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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the carbon steel and gray cast iron piping, piping components, and tanks exposed to lubricating oil in the Emergency Cooling Water System, Emergency Diesel Generator System, Fire Protection System, and Standby Liquid Control System.
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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components exposed to lubricating oil in the Emergency Diesel Generator System and High Pressure Service Water System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-099	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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the aluminum alloy, copper alloy, and stainless steel heat exchanger components, piping, piping components exposed to lubricating oil in the Emergency Diesel Generator System, High Pressure Service Water System, and Standby Liquid Control System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted and will be used to manage loss of material of the copper alloy piping, piping components exposed to lubricating oil in the Turbine Building Closed Cooling Water System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-100	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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the stainless steel heat exchanger components, piping, piping components, and tanks exposed to lubricating oil in the Emergency Diesel Generator System, High Pressure Service Water System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Reactor Recirculation System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted and will be used to manage loss of material of the stainless steel piping, piping components exposed to lubricating oil in the Turbine Building Closed Cooling Water System.
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 tubes exposed to lubricating oil in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Consistent with NUREG-2191. The Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.27) program will be used to manage reduction of neutron absorbing capacity; change in dimensions and loss of material of the Boralcan (Rio Tinto Alcan Composite) fuel storage racks: neutron absorbing sheets exposed to treated water in the Reactor Building.
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, piping components exposed to soil or concrete in Auxiliary Systems.
3.3.1-104	HDPE, fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no HDPE, fiberglass piping, piping components exposed to soil or concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-105	This Item Number is not used in NUREG-2192.				
3.3.1-106	This Item Number is not used in NUREG-2192.				
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. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage loss of material of the stainless steel piping, piping components exposed to concrete and soil in the Refueling Water Storage and Transfer System.
3.3.1-108	Titanium, super austenitic, copper alloy, stainless steel, nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no titanium, super austenitic, copper alloy, nickel alloy piping, piping components, tanks, and closure bolting exposed to soil, concrete, or underground in Auxiliary Systems. The loss of material in stainless steel piping, piping components exposed to soil and concrete is addressed by Item Number 3.3.1-107.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-109	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. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage loss of material of the carbon and low alloy steel, carbon steel, ductile iron, and gray cast iron closure bolting, piping, piping components, and tanks exposed to concrete, soil, and underground in the Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, and High Pressure Service Water System.
3.3.1-109a	This Item Number is not used in NUREG-2192.				
3.3.1-110	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Not Applicable. There are no nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F) in Auxiliary Systems. Cracking in stainless steel piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F) is addressed in Item Number 3.3.1-016.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-111	Steel structural steel exposed to air-indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Not Applicable. There is no steel structural steel exposed to air-indoor uncontrolled in Auxiliary Systems.
3.3.1-112	Steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. See Subsection 3.3.2.2.9.
3.3.1-113	Aluminum piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191.
3.3.1-114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
3.3.1-115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in Auxiliary Systems.
3.3.1-116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-117	Glass piping elements exposed to air, lubricating oil, closed-cycle cooling water, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, underground	None	None	No	Consistent with NUREG-2191.
3.3.1-118	This Item Number is not used in NUREG-2192.				
3.3.1-119	Nickel alloy, PVC, glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable)	None	None	No	Consistent with NUREG-2191.
3.3.1-120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191.
3.3.1-122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Consistent with NUREG-2191.
3.3.1-123	Titanium heat exchanger components other than tubes, piping and piping components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium heat exchanger components other than tubes, piping and piping components exposed to raw water in Auxiliary Systems.
3.3.1-124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no 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) or treated borated water >60°C (>140°F) in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-125	Stainless steel, steel (with stainless steel cladding), nickel alloy spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel structural bolting, equipment storage racks (inside spent fuel pool and reactor well), fuel storage racks (spent fuel), and metal components exposed to treated water in the Reactor Building. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel and stainless steel piping, piping components exposed to treated water and raw water in the Auxiliary Steam System, Control Rod Drive System, Emergency Service Water System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Reactor Water Cleanup System, Service Water System, and Traveling Water Screen System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-127	Metallic piping, piping components, tanks exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage loss of material in carbon steel piping, piping components exposed to raw water in the Emergency Service Water System, High Pressure Service Water System, and Service Water System. Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage loss of material in carbon steel piping, piping components exposed to raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation. See Subsection 3.3.2.2.7.
3.3.1-128	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program will be used to manage loss of material of the carbon steel tanks exposed to air-outdoor and soil in the Refueling Water Storage and Transfer System.
3.3.1-129	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-130	Metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water	Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in raw water, raw water (potable), treated water only); flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage flow blockage and loss of material of the copper alloy piping, piping components, spray nozzles, and sprinklers exposed to air-outdoor, condensation, and raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.
3.3.1-131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage flow blockage of the carbon steel, copper alloy, ductile iron, galvanized steel, gray cast iron, and stainless steel piping, piping components, and spray nozzles exposed to condensation in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-132	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 (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage cracking and loss of material of the insulated carbon steel, copper alloy, ductile iron, and gray cast iron piping, piping components exposed to air-outdoor and condensation in the Chilled Water System, Domestic Water System, Emergency Service Water System, High Pressure Service Water System, Reactor Building Closed Cooling Water System, Refueling Water Storage and Transfer System, Service Water System, and Turbine Building Closed Cooling Water System.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no HDPE underground piping, piping components in Auxiliary Systems.
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.2.1.25) program will be used to manage loss of material of the carbon steel, copper alloy, and stainless steel piping, piping components, and traveling screens exposed to raw water in the Traveling Water Screen System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the gray cast iron piping, piping components exposed to waste water in the Plant Equipment and Floor Drain System.
3.3.1-136	Steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion, MIC (raw water, raw water (potable), treated water, soil only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron piping, piping components, and tanks exposed to air-indoor uncontrolled and air-outdoor in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-137	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	The ASME Section XI, Subsection IWF (B.2.31) program has been substituted and will be used to manage loss of material of the carbon steel, galvanized steel, and stainless steel supports for ASME Class 2 and 3 piping and components and ASME class MC components exposed to raw water and treated water in the Component Supports commodity group. The Structures Monitoring (B.2.34) program has been substituted and will be used to manage loss of material of the carbon steel, galvanized steel, and stainless steel penetration seals and supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, Non-ASME piping and components exposed to raw water and treated water in the Component Supports commodity group and Hazard Barriers and Elastomers commodity group.
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program will be used to manage loss of coating or lining integrity of the carbon steel (with internal coating), ductile iron (with internal coating), galvanized steel, gray cast iron (with internal coating), and stainless steel (with internal coating) heat exchanger components, piping, piping components, and tanks exposed to

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					lubricating oil, raw water, treated water, and waste water in the Auxiliary Steam System, Emergency Service Water System, Fire Protection System, High Pressure Service Water System, Plant Equipment and Floor Drain System, Radwaste System, Standby Liquid Control System, and High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel (with internal coating) tanks exposed to raw water and treated water in the Radwaste System and Reactor Water Cleanup System. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel (with internal coating) tanks exposed to treated water in the Refueling Water Storage and Transfer System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program will be used to manage loss of material of the carbon steel (with internal coating), ductile iron (with internal coating), galvanized steel, gray cast iron (with internal coating), and stainless steel (with internal coating) heat exchanger components, piping, piping components, and tanks exposed to raw water, treated water, and waste water in the Auxiliary Steam System, Emergency Service Water System, Fire Protection System, High Pressure Service Water System, Plant Equipment and Floor Drain System, Radwaste System, and Standby Liquid Control System. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted and will be used to manage loss of material of the carbon steel (with internal coating) tanks exposed to raw water and treated water in the Radwaste System and Reactor Water Cleanup System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program has been substituted and will be used to manage loss of material of the carbon steel (with internal coating) tanks exposed to treated water in the Refueling Water Storage and Transfer System.
3.3.1-140	Gray cast iron, ductile iron piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program will be used to manage loss of material of the ductile iron (with internal coating) and gray cast iron (with internal coating) piping, piping components exposed to raw water in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program implementation.
3.3.1-141	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-142	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposed to raw water and waste water in the Emergency Cooling Water System, Emergency Service Water System, Fire Protection System, High Pressure Service Water System, Plant Equipment and Floor Drain System, and Traveling Water Screen System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.3.1-143	This Item Number is not used in NUREG-2192.				
3.3.1-144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage cracking of stainless steel piping, piping components exposed to concrete and soil in the Refueling Water Storage and Transfer System. Cracking due to SCC in steel is not an applicable aging effect/mechanism since soil and concrete are not a carbonate/bicarbonate environment.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-145	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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of stainless steel closure bolting exposed to air-indoor uncontrolled and air-outdoor in the Condensate Transfer System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Radiation Monitoring System, Radwaste System, Reactor Water Cleanup System, Service Water System, Standby Liquid Control System, and Water Treatment System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
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	Not Applicable. There are no stainless steel underground piping, piping components, and tanks in Auxiliary Systems. See Subsection 3.3.2.2.3.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-147	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, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water in Auxiliary Systems.
3.3.1-148	This Item Number is not used in NUREG-2192.				
3.3.1-149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no fiberglass piping, piping components, ducting and ducting components exposed to air-outdoor in 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	The Structures Monitoring (B.2.34) program has been substituted and will be used to manage cracking, blistering, and loss of material of the fiberglass hazard barriers exposed to air-indoor uncontrolled in the Hazard Barriers and Elastomers commodity group.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air or condensation with a heat transfer intended function in Auxiliary Systems.
3.3.1-152	This Item Number is not used in NUREG-2192.				
3.3.1-153	This Item Number is not used in NUREG-2192.				
3.3.1-154	This Item Number is not used in NUREG-2192.				
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, and tanks exposed to waste water >60°C (>140°F) in Auxiliary Systems.
3.3.1-156	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-157	Steel piping, piping components, heat exchanger components exposed to air-outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.17) program will be used to manage loss of material of the ductile iron and gray cast iron piping, piping components exposed to air-outdoor in the Fire Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.17) program implementation.
3.3.1-158	Nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no nickel alloy piping, piping components, and heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water in Auxiliary Systems.
3.3.1-159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no fiberglass piping, piping components, ducting, and ducting components exposed to air in Auxiliary Systems.
3.3.1-160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38,	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage cracking of copper alloy with greater than 15% zinc heat exchanger components, piping, piping components exposed to raw water in the

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
	cooling water, raw water, waste water		"Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"		Emergency Cooling Water System, Emergency Service Water System, and Service Water System. Consistent with NUREG-2191 with exceptions. The Closed Treated Water Systems (B.2.1.12) program will be used to manage cracking of copper alloy with greater than 15% zinc heat exchanger components, piping, piping components exposed to closed cycle cooling water in the Chilled Water System, Emergency Diesel Generator System, Reactor Building Closed Cooling Water System, and Turbine Building Closed Cooling Water System. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B.2.1.12) program implementation. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program has been substituted and will be used to manage cracking of copper alloy with greater than 15% zinc metal components exposed to raw water in the Circulating Water Pump Structure.
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 with a heat transfer intended function in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-162	This Item Number is not used in NUREG-2192.				
3.3.1-163	This Item Number is not used in NUREG-2192.				
3.3.1-164	This Item Number is not used in NUREG-2192.				
3.3.1-165	This Item Number is not used in NUREG-2192.				
3.3.1-166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in Auxiliary Systems.
3.3.1-167	Zinc piping components exposed to air-indoor controlled, air - indoor uncontrolled	None	None	No	Consistent with NUREG-2191.
3.3.1-168	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no steel, copper alloy piping, piping components exposed to steam in 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, piping components exposed to steam in Auxiliary Systems.
3.3.1-171	This Item Number is not used in NUREG-2192.				
3.3.1-172	PVC piping, piping components exposed to air-outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program has been substituted and will be used to manage reduction in impact strength in PVC cooling tower drift eliminators exposed to air-outdoor in the Emergency Cooling Tower and Reservoir.
3.3.1-173	This Item Number is not used in NUREG-2192.				
3.3.1-174	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-175	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 piping, piping components, and tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, or waste water in Auxiliary Systems.
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, and tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, or waste water in Auxiliary Systems.
3.3.1-177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no fiberglass piping, piping components exposed to soil in Auxiliary Systems.
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not Applicable. There are no fiberglass piping and piping components exposed to concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-179	Masonry walls: structural fire barriers exposed to air	Cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.M26, "Fire Protection," and AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program and Masonry Walls (B.2.1.33) program will be used to manage cracking and loss of material (spalling, scaling) of concrete block fire barriers exposed to air-indoor uncontrolled in the Fire Protection System.
3.3.1-180	This Item Number is not used in NUREG-2192.				
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not Applicable. There are no titanium piping, piping components exposed to condensation in Auxiliary Systems.
3.3.1-182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage reduced thermal insulation resistance of the aluminum, calcium silicate, caulking and lagging adhesive, cellular glass, fiberglass, foamed plastic, insulation cement and finishing cement, mineral fiber, plastic mastic jacketing, silicone, and stainless steel thermal insulation and thermal insulation jacketing exposed to air-indoor uncontrolled and air-outdoor in the Insulation commodity group.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-183	This Item Number is not used in NUREG-2192.				
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There are no PVC piping, piping components, and tanks exposed to concrete in Auxiliary Systems.
3.3.1-185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, or treated water in Auxiliary Systems.
3.3.1-186	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, or waste water in Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3.1-187	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-188	This Item Number is not used in NUREG-2192.				
3.3.1-189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of aluminum alloy piping, piping components exposed to air-indoor uncontrolled in the Backup Instrument Nitrogen to ADS System, Battery and Emergency Switchgear Ventilation System, Emergency Diesel Generator System, Fire Protection System, and Safety Grade Instrument Gas System. See Subsection 3.3.2.2.8.
3.3.1-190	This Item Number is not used in NUREG-2192.				
3.3.1-191	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum underground piping, piping components, and tanks in Auxiliary Systems. See Subsection 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.2.1.21) program will be used to manage long-term loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to raw water, sodium pentaborate solution, treated water, and waste water in the Auxiliary Steam System, Chilled Water System, Condensate Transfer System, Control Rod Drive System, Domestic Water System, Emergency Cooling Water System, Emergency Diesel Generator System, Emergency Service Water System, Fire Protection System, Fuel Pool Cooling and Cleanup System, High Pressure Service Water System, Offgas and Recombiner System, Plant Equipment and Floor Drain System, Post Accident Sampling System, Process Sampling System, Radwaste System, Reactor Water Cleanup System, Refueling Water Storage and Transfer

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					System, Service Water System, Standby Liquid Control System, Torus Water Cleanup System, Traveling Water Screen System, Water Treatment System, Core Spray System, High Pressure Coolant Injection System, Primary Containment Isolation System, Reactor Core Isolation Cooling System, and Residual Heat Removal System. The Bolting Integrity (B.2.1.10) program has been substituted and will be used to manage long-term loss of material of the carbon and low alloy steel closure bolting exposed to waste water in the Plant Equipment and Floor Drain System.
3.3.1-194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no PVC piping, piping components, and tanks exposed to soil in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-195	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, cementitious piping, piping components exposed to raw water or treated water in Auxiliary Systems.
3.3.1-196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no HDPE piping, piping components exposed to raw water or treated water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-197	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel piping, piping components exposed to air-indoor uncontrolled in the Fire Protection System.
3.3.1-198	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC (all metallic materials except aluminum; in liquid environments only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel and copper alloy piping, piping components exposed to condensation and 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 Programs	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.2.1.13) program will be used to manage cracking, loss of material, and loss of preload of the carbon and low alloy steel structural bolting and high strength low alloy steel structural bolting with yield strength of 150 ksi or greater exposed to air-indoor uncontrolled and air-outdoor in the Cranes and Hoists System and Fuel Handling System.
3.3.1-200	This Item Number is not used in NUREG-2192.				
3.3.1-201	This Item Number is not used in NUREG-2192.				
3.3.1-202	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Not applicable. See Subsection 3.3.2.2.9.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-203	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 exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon or low alloy steel with stainless steel cladding, and stainless steel heat exchanger components, piping, piping components, and tanks exposed to sodium pentaborate solution and treated water in the Auxiliary Steam System, Condensate Transfer System, Control Rod Drive System, Emergency Service Water System, Fuel Pool Cooling and Cleanup System, Offgas and Recombiner System, Post Accident Sampling System, Process Sampling System, Reactor Water Cleanup System, Refueling Water Storage and Transfer System, Service Water System, Standby Liquid Control System, Suppression Pool Temperature Monitoring System, Torus Water Cleanup System, and Water Treatment System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-204	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-205	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of insulated stainless steel piping, piping components exposed to air-outdoor and condensation in the Chilled Water System, Emergency Service Water System, Refueling Water Storage and Transfer System, and Service Water System. See Subsection 3.3.2.2.3.
3.3.1-206	This Item Number is not used in NUREG-2192.				
3.3.1-207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage cracking of the titanium heat exchanger tubes exposed to raw water in the Main Condenser System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-208	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in Auxiliary Systems.
3.3.1-209	This Item Number is not used in NUREG-2192.				
3.3.1-210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in Auxiliary Systems.
3.3.1-211	This Item Number is not used in NUREG-2192.				
3.3.1-212	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-213	This Item Number is not used in NUREG-2192.				
3.3.1-214	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in Auxiliary Systems.
3.3.1-215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in 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 exposed to air, condensation, soil, or concrete in Auxiliary Systems.
3.3.1-217	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-218	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 exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in 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, piping components exposed to steam in Auxiliary Systems.
3.3.1-220	This Item Number is not used in NUREG-2192.				
3.3.1-221	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-222	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the stainless steel tanks exposed to air-indoor uncontrolled and condensation in the Fuel Pool Cooling and Cleanup System, Plant Equipment and Floor Drain System, Radiation Monitoring System, and Standby Liquid Control System. See Subsection 3.3.2.2.4.
3.3.1-223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum underground piping, piping components, and tanks in Auxiliary Systems. See Subsection 3.3.2.2.10.
3.3.1-224	This Item Number is not used in NUREG-2192.				
3.3.1-225	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-226	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Auxiliary Systems.
3.3.1-227	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems. See Subsection 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	Not Applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.4.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-229	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Auxiliary Systems.
3.3.1-230	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Auxiliary Systems.
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	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.3.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-232	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the insulated stainless steel piping, piping components exposed to air-outdoor and condensation in the Chilled Water System, Emergency Service Water System, Refueling Water Storage and Transfer System, and Service Water System. See Subsection 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	Not applicable. There are no insulated aluminum piping, piping components, and tanks exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.8.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-234	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material in aluminum alloy piping, piping components exposed to air-indoor uncontrolled and condensation in the Backup Instrument Nitrogen to ADS System, Battery and Emergency Switchgear Ventilation System, Emergency Diesel Generator System, Fire Protection System, Radiation Monitoring System, Safety Grade Instrument Gas System, and Standby Liquid Control System. See Subsection 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.2.1.14) program will be used to manage loss of material of the aluminum alloy, carbon steel, copper alloy, and stainless steel piping, piping components exposed to air-dry in the Backup Instrument Nitrogen to ADS System, Battery and Emergency Switchgear Ventilation System, Control Room Ventilation System, Safety Grade Instrument Gas System, Primary Containment Isolation System, Standby Gas Treatment System, and Main Steam System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water in Auxiliary Systems.
3.3.1-237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Consistent with NUREG-2191.
3.3.1-238	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in Auxiliary Systems.
3.3.1-239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-240	Aluminum heat exchanger components exposed to waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum heat exchanger components exposed to waste water in Auxiliary Systems. See Subsection 3.3.2.2.10.
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of stainless steel heat exchanger components exposed to air-indoor uncontrolled in the Chilled Water System. See Subsection 3.3.2.2.4.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-242	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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material in aluminum alloy heat exchanger components exposed to condensation in the Core Spray System and Residual Heat Removal System. See Subsection 3.3.2.2.10.
3.3.1-243	This Item Number is not used in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-244	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 exceptions. The One-Time Inspection (B.2.1.21) and Water Chemistry (B.2.1.2) program will be used to manage cracking of cast austenitic stainless steel and stainless steel piping, piping components exposed to treated water > 140 F and treated water > 482 F in the Control Rod Drive System, Offgas and Recombiner System, Post Accident Sampling System, Process Sampling System, Reactor Water Cleanup System, and Refueling Water Storage and Transfer System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-245	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not applicable. There are no insulated aluminum piping, piping components, and tanks exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-246	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	Not Applicable. There are no stainless steel, nickel alloy underground piping, piping components, and tanks in Auxiliary Systems. See Subsection 3.3.2.2.4.
3.3.1-247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. There are no aluminum piping, piping components, and tanks exposed to raw water and waste water in Auxiliary Systems. See Subsection 3.3.2.2.10.
3.3.1-248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, and tanks exposed to air with borated water leakage in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-249	Steel heat exchanger tubes internal to components exposed to air-outdoor, air-indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to condensation in the Chilled Water System and Service Water System.
3.3.1-250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil) in Auxiliary Systems.
3.3.1-251	This Item Number is not used in NUREG-2192.				
3.3.1-252	Aluminum piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no aluminum piping, piping components exposed to soil or concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the PVC piping, piping components, and tanks exposed to raw water in the Emergency Service Water System, Process Sampling System, and Service Water System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program has been substituted for the Fire Water System (B.2.1.17) program (specified in NUREG-2191 Item VII.G.A-787b) and will be used to manage loss of material of the PVC tanks exposed to treated water in the Emergency Service Water System.
3.3.1-254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not applicable. . See Subsection 3.3.2.2.8.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.16) program will be used to manage loss of material of the galvanized steel fire barriers exposed to air-indoor uncontrolled in the Fire Protection System.
3.3.1-256	This Item Number is not used in NUREG-2192.				
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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage reduction of heat transfer of the copper alloy and stainless heat exchanger tubes exposed to lubricating oil in the Emergency Diesel Generator System and High Pressure Service Water System.
3.3.1-258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water with a flow rate or heat transfer function in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no aluminum piping, piping components exposed to raw water in Auxiliary Systems.
3.3.1-260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material and loss of preload of the carbon and low alloy steel HVAC closure bolting exposed to air-indoor uncontrolled in the Battery and Emergency Switchgear Ventilation System, Control Room Ventilation System, Diesel Generator Building Ventilation System, Pump Structure Ventilation System, Secondary Containment System, and Standby Gas Treatment System.
3.3.1-261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water or raw water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium piping, piping components, and heat exchanger components exposed to closed-cycle cooling water in Auxiliary Systems. Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) piping, piping components exposed to treated water are addressed by Item Number 3.3.1-237.
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. Fiberglass hazard barriers exposed to air-indoor uncontrolled are addressed by Item Number 3.3.1-150. PVC piping, piping components, and tanks exposed to raw water and treated water are addressed by Item Number 3.3.1-253. PVC piping, piping components, and tanks exposed to air-indoor uncontrolled and condensation are addressed by Item Number 3.3.1-119.

Table 3.3.2-1
Auxiliary Steam System
Summary of Aging Management Evaluation

Table 3.3.2-1 Auxiliary Steam System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Heat Exchanger - (Condensate Return Unit Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
Heat Exchanger - (Condensate Return Unit Cooler) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
Heat Exchanger - (HVAC Heater Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (HVAC Heater Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
Heat Exchanger - (HVAC Heater Coils) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
Heat Exchanger - (Heating System Condensate Coolers) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
		Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	C
Heat Exchanger - (Unit Heaters) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	D
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
						VIII.E.S-16	3.4.1-005	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-32	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
Pump Casing (Condensate Pumps)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
Tanks (Condensate Return Tanks)	Leakage Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E4.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E4.A-414	3.3.1-139	B

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-32	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A

Table 3.3.2-1 Auxiliary Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-1 Auxiliary Steam System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-2
Backup Instrument Nitrogen to ADS System
Summary of Aging Management Evaluation

Table 3.3.2-2 Backup Instrument Nitrogen to ADS System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Accumulator (Instrument N2 Accumulator)	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Hoses	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
Piping, piping components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A

Table 3.3.2-2 Backup Instrument Nitrogen to ADS System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Valve Body	Pressure Boundary	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.F2.A-763a	3.3.1-234	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-2 Backup Instrument Nitrogen to ADS System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-3
Battery and Emergency Switchgear Ventilation System
Summary of Aging Management Evaluation

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-08	3.3.1-090	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-08	3.3.1-090	A
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-113	3.3.1-082	A

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Elastomer	Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-504	3.3.1-085	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.F2.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.F2.A-763a	3.3.1-234	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.F2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.F2.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-3 Battery and Emergency Switchgear Ventilation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-4
Chilled Water System
Summary of Aging Management Evaluation

Table 3.3.2-4 Chilled Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Drip Pan	Leakage Boundary	Galvanized Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-08	3.3.1-090	C, 1
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-08	3.3.1-090	C
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	C
Heat Exchanger - (Cable Spreading Room Cooling Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Cable Spreading Room Cooling Coils) Tube Side Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
Heat Exchanger - (Cable Spreading Room Cooling Coils) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Control Room A/C Supply Cooling Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
Heat Exchanger - (Control Room A/C Supply Cooling Coils) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Control Room North Office Cooling Coil) Tube Side Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Control Room North Office Cooling Coil) Tube Side Components	Leakage Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	C
Heat Exchanger - (Control Room North Office Cooling Coil) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Drywell Area Cooling Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
Heat Exchanger - (Drywell Area Cooling Coils) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Drywell Equipment Sump Cooler) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	C

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Drywell Equipment Sump Cooler) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.F3.A-770a	3.3.1-241	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	D
Heat Exchanger - (Health Physics and Chem Labs Supply Cooling Coils) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
Heat Exchanger - (Health Physics and Chem Labs Supply Cooling Coils) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tube Sheet	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	C

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tube Sheet	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
			Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-778	3.3.1-249	A
Heat Exchanger - (Recirc Pump Motor Air Cooler) Tubes	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	C
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
		Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	A
			Condensation (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
		Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
		Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.I.A-734b	3.3.1-205	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-761c	3.3.1-232	A

Table 3.3.2-4 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)			H, 2
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
		Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
			Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A

Table 3.3.2-4 Chilled Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The drip pans are located internal to the fan assemblies, and therefore the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the applicable aging effects.

2. Wall thinning due to erosion has been determined to be an applicable aging effect for this system.

Table 3.3.2-5

Condensate Transfer System

Summary of Aging Management Evaluation

Table 3.3.2-5 Condensate Transfer System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-5 Condensate Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-5 Condensate Transfer System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-6
Control Rod Drive System
Summary of Aging Management Evaluation

Table 3.3.2-6 Control Rod Drive System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Accumulator (HCU)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B

Table 3.3.2-6 Control Rod Drive System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-6 Control Rod Drive System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Cumulative Fatigue Damage, Cracking	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Cumulative Fatigue Damage, Cracking	TLAA	V.D2.E-10	3.2.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Piping, piping components: Class 1 piping, fittings and branch connections less than 4” NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-6 Control Rod Drive System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.3.2-6 Control Rod Drive System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Rupture Disks	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
	Pressure Relief	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-6 Control Rod Drive System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.3.2-6 Control Rod Drive System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-7

Control Room Ventilation System

Summary of Aging Management Evaluation

Table 3.3.2-7 Control Room Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F1.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F1.A-794	3.3.1-260	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-08	3.3.1-090	A
		Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-504	3.3.1-085	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-08	3.3.1-090	A
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A

Table 3.3.2-7 Control Room Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-113	3.3.1-082	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A

Table 3.3.2-7 Control Room Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Structural Integrity (Attached)	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A

Table 3.3.2-7 Control Room Ventilation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-8

Cranes and Hoists System

Summary of Aging Management Evaluation

Table 3.3.2-8 Cranes and Hoists System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
			Air - Outdoor (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A

Table 3.3.2-8 Cranes and Hoists System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Cranes: Rails, Bridges, Structural Members, Structural Components	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Cumulative Fatigue Damage	TLAA	VII.B.A-06	3.3.1-001	A, 1
				Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
						VII.B.A-07	3.3.1-052	A
			Air - Outdoor (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Cumulative Fatigue Damage	TLAA	VII.B.A-06	3.3.1-001	A, 1
				Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-8 Cranes and Hoists System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Cranes: Rails, Bridges, Structural Members, Structural Components	Structural Support	Carbon Steel	Air - Outdoor (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-8 Cranes and Hoists System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.7.

Table 3.3.2-9

Diesel Generator Building Ventilation System

Summary of Aging Management Evaluation

Table 3.3.2-9 Diesel Generator Building Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F4.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F4.A-794	3.3.1-260	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F4.A-08	3.3.1-090	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F4.A-08	3.3.1-090	A
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-113	3.3.1-082	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F4.A-504	3.3.1-085	A

Table 3.3.2-9 Diesel Generator Building Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Elastomer	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-9 Diesel Generator Building Ventilation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-10
Domestic Water System
Summary of Aging Management Evaluation

Table 3.3.2-10 Domestic Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Insulated Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Copper Alloy with Greater Than 15% Zinc	Condensation (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-271	3.3.1-093	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
		Gray Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-10 Domestic Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-270	3.3.1-088	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
Insulated piping, piping components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Copper Alloy with Greater Than 15% Zinc	Condensation (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-271	3.3.1-093	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A

Table 3.3.2-10 Domestic Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-11
Emergency Cooling Water System
Summary of Aging Management Evaluation

Table 3.3.2-11 Emergency Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping elements	Leakage Boundary	Glass	Air - Outdoor (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-127	3.3.1-097	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-127	3.3.1-097	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Pump Casing (ECW Pump)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Gray Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (ECW Pump)	Pressure Boundary	Gray Cast Iron	Raw Water (External)	Loss of Material	Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
Pump Casing (ESW Booster Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
Pump Casing (Emergency Cooling Tower Sump Pump)	Leakage Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Gray Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Emergency Cooling Tower Sump Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.C1.AP-127	3.3.1-097	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-11 Emergency Cooling Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-12
Emergency Diesel Generator System
Summary of Aging Management Evaluation

Table 3.3.2-12 Emergency Diesel Generator System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Compressor Housing (D/G Starting Air)	Structural Integrity (Attached)	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
Electric Heaters (D/G Jacket Coolant and D/G Lube Oil Standby Heater Housings)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Electric Heaters (D/G Jacket Coolant and D/G Lube Oil Standby Heater Housings)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
Expansion Joint	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
Flame Arrestor	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-043	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-043	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
Heat Exchanger - (D/G Air Coolant Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	D
Heat Exchanger - (D/G Air Coolant Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	D
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (D/G Air Coolant Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	B
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	D
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	C

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Jacket Coolant Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	D
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	D
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (D/G Jacket Coolant Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	B
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	D
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (D/G Lube Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-131	3.3.1-098	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Lube Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	C
Heat Exchanger - (D/G Lube Oil Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	VII.H2.A-791	3.3.1-257	A
					One-Time Inspection (B.2.1.21)	VII.H2.A-791	3.3.1-257	A
		Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	VII.H2.A-791	3.3.1-257	A
					One-Time Inspection (B.2.1.21)	VII.H2.A-791	3.3.1-257	A
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	C
		Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	C
Hoses	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Fuel Oil (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H1.A-660	3.3.1-085	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hoses	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Closed Cycle Cooling Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C2.AP-259	3.3.1-085	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E3.A-504	3.3.1-085	A
			Fuel Oil (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H1.A-660	3.3.1-085	A
			Lubricating Oil (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
			Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
			Fuel Oil (Internal)	None	None	VII.J.AP-49	3.3.1-117	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Pressure Boundary	Glass	Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-24	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	B
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Gray Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-043	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-136	3.3.1-071	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-136	3.3.1-071	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-138	3.3.1-100	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-138	3.3.1-100	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
Pump Casing (D/G Fuel Oil Auxiliary)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
Pump Casing (D/G Fuel Oil Transfer)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
Pump Casing (D/G Jacket Coolant Standby Circ)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (D/G Jacket Coolant Standby Circ)	Pressure Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Pump Casing (D/G Lube Oil Pre-Lube)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
Pump Casing (D/G Lube Oil Standby Circ)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
Pump Casing (Flex Fuel Oil Transfer)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
Strainer (Element)	Filter	Carbon Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
		Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-136	3.3.1-071	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-136	3.3.1-071	A
			Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	A
Tanks (D/G Coolant Expansion Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
Tanks (D/G Dirty Fuel Oil Drain)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (D/G Dirty Fuel Oil Drain)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tanks (D/G Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
Tanks (D/G Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	C
Tanks (D/G Lube Oil Storage)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (D/G Lube Oil Storage)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
Tanks (D/G Starting Air Reservoir)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-763a	3.3.1-234	A
			Air - Indoor Uncontrolled (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.A-451a	3.3.1-189	A, 2
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-763a	3.3.1-234	A, 2
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-255	3.3.1-048	B

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Aluminum Alloy	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-129	3.3.1-071	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-129	3.3.1-071	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-162	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-162	3.3.1-099	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	B
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.H2.AP-43	3.3.1-072	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-132	3.3.1-069	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-132	3.3.1-069	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-133	3.3.1-099	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 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.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
			Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-105	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-105	3.3.1-070	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-043	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.H1.AP-136	3.3.1-071	A
					One-Time Inspection (B.2.1.21)	VII.H1.AP-136	3.3.1-071	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-138	3.3.1-100	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.H2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.AP-221a	3.3.1-006	A

Table 3.3.2-12 Emergency Diesel Generator System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

2. Based on the configuration of these valves, there is no potential for the accumulation of condensation. Therefore, air-indoor (uncontrolled) has been selected as the internal environment.

Table 3.3.2-13
Emergency Service Water System
Summary of Aging Management Evaluation

Table 3.3.2-13 Emergency Service Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Flexible Connection	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Raw Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.AP-75	3.3.1-085	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Core Spray Pump Room Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (Core Spray Pump Room Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (D/G Air Coolant Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Heat Exchanger - (D/G Air Coolant Cooler) Tube Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Air Coolant Cooler) Tube Side Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	C
Heat Exchanger - (D/G Air Coolant Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Jacket Coolant Cooler) Tube Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	C
Heat Exchanger - (D/G Jacket Coolant Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Heat Exchanger - (D/G Lube Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Lube Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Heat Exchanger - (D/G Lube Oil Cooler) Tube Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	C
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	C
Heat Exchanger - (D/G Lube Oil Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
		Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
		Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (D/G Lube Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
Heat Exchanger - (HPCI Pump Room Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (HPCI Pump Room Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RCIC Pump Room Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RCIC Pump Room Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RHR Pump Room Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RHR Pump Room Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RHR Pump Room Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Insulated Valve Body	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3.1-126	A
		Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.I.A-734b	3.3.1-205	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-761b	3.3.1-232	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3.1-126	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-284	3.3.1-109	A
		PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-787c	3.3.1-253	A
		Titanium	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-160	3.3.1-122	A
			Treated Water (Internal)	None	None	VII.J.A-766	3.3.1-237	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-284	3.3.1-109	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Piping, piping components with Internal Coatings	Pressure Boundary	Stainless Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.C1.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.C1.A-414	3.3.1-139	B
Pump Casing (ESW Chemical Injection Pumps)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (ESW Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Gray Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
Tanks (Chemical Tank)	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	C
			Condensation (Internal)	None	None	VII.J.AP-269	3.3.1-119	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Chemical Tank)	Leakage Boundary	PVC	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-787b	3.3.1-253	E, 1
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-284	3.3.1-109	A
		PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-787c	3.3.1-253	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
		Titanium	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-160	3.3.1-122	A
			Treated Water (Internal)	None	None	VII.J.A-766	3.3.1-237	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-13 Emergency Service Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-14
Fire Protection System
Summary of Aging Management Evaluation

Table 3.3.2-14 Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Concrete elements: Curbs	Fire Barrier	Concrete	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
				Loss of Material	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
			Air - Outdoor (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
				Loss of Material	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fire Barriers	Fire Barrier	Subliming Compound with and without Reinforcement	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)			F, 1
				Loss of Material	Fire Protection (B.2.1.16)			F, 1
Fire Barriers (Damper Assembly)	Fire Barrier	Galvanized Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.A-789	3.3.1-255	A
			Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	C
Fire Barriers (For Steel Components)	Fire Barrier	Cementitious Fireproofing	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)			F, 2
								F, 2
Fire Barriers- concrete walls, ceilings, floors	Fire Barrier	Concrete	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
				Loss of Material	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
			Air - Outdoor (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
				Loss of Material	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
Fire Barriers- doors	Fire Barrier	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	C
						VII.G.A-21	3.3.1-059	A
			Air - Outdoor (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	C
						VII.G.A-21	3.3.1-059	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fire Barriers-masonry walls	Fire Barrier	Concrete Block	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B.2.1.33)	VII.G.A-626	3.3.1-179	A
				Loss of Material (Spalling, Scaling) and Cracking	Fire Protection (B.2.1.16)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B.2.1.33)	VII.G.A-626	3.3.1-179	A
Fire Barriers-penetration seals	Fire Barrier	Aluminum Silicate	Air - Indoor Uncontrolled (External)	Change in Material Properties	Fire Protection (B.2.1.16)			F, 3
				Cracking	Fire Protection (B.2.1.16)			F, 3
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	C
		Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	Fire Protection (B.2.1.16)	VII.G.A-19	3.3.1-057	A
		Grout	Air - Indoor Uncontrolled (External)	Cracking	Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
					Fire Protection (B.2.1.16)	VII.G.A-90	3.3.1-060	A
					Structures Monitoring (B.2.1.34)	VII.G.A-90	3.3.1-060	A
Fire Hydrant	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
		Ductile Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fire Hydrant	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
					Selective Leaching (B.2.1.22)	VII.G.A-02	3.3.1-072	A
		Gray Cast Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-149	3.3.1-063	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
					Selective Leaching (B.2.1.22)	VII.G.A-02	3.3.1-072	A
Flame Arrestor	Pressure Boundary	Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
Gearbox	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.G.AP-127	3.3.1-097	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-127	3.3.1-097	A
Hose Stations	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
Odorizer	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.G.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-763a	3.3.1-234	A
			Gas (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
			Gas (Internal)	None	None	VII.J.AP-98	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
			Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.G.A-649	3.3.1-197	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
			Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 4
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-088	A
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
						VII.G.A-400	3.3.1-127	B
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
		Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-722	3.3.1-157	B
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-722	3.3.1-157	B
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components with Internal Coatings	Pressure Boundary	Ductile Iron (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
					Selective Leaching (B.2.1.22)	VII.G.A-02	3.3.1-072	A
		Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components with Internal Coatings	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
					Selective Leaching (B.2.1.22)	VII.G.A-02	3.3.1-072	A
Pump Casing (Diesel Driven Fire Pump Fuel Oil Transfer Pump)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
Spray Nozzles	Spray	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.G.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-763a	3.3.1-234	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
		Copper Alloy with Greater Than 15% Zinc	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Condensation (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
		Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.G.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.AP-221a	3.3.1-006	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.G.AP-209a	3.3.1-004	A
				Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.AP-221a	3.3.1-006	A
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
		Copper Alloy with Greater Than 15% Zinc (with Chrome Plating)	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc (with Chrome Plating)	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
	Spray	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
		Copper Alloy with Greater Than 15% Zinc (with Chrome Plating)	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc (with Chrome Plating)	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
Strainer (Element)	Filter	Stainless Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-136a	3.3.1-071	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A
Tanks (Diesel Fire Pump Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-26	3.3.1-055	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A
Tanks (Emergency D/G BLDG Cardox)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Emergency D/G BLDG Cardox)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Tanks (Foam Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
Tanks (Retard Chamber)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
Tanks (Turbine Building Cardox Unit)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.G.A-649	3.3.1-197	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-650	3.3.1-198	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	D
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-132a	3.3.1-069	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-47	3.3.1-072	A
		Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	B
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-058	A
					Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-722	3.3.1-157	B
			Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-404	3.3.1-131	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-143	3.3.1-089	B
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.19)	VII.G.AP-234	3.3.1-070	A
					One-Time Inspection (B.2.1.21)	VII.G.AP-234	3.3.1-070	A
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.A-532	3.3.1-193	A
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A

Table 3.3.2-14 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
					Selective Leaching (B.2.1.22)	VII.G.A-02	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.G.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.G.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-066	B
Valve Body with Internal Coatings	Pressure Boundary	Ductile Iron (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-412	3.3.1-136	D
			Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-064	B
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B

Table 3.3.2-14 Fire Protection System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. Subliming Compound with and without Reinforcement are fire-resistant insulation and coating materials potentially subject to cracking and loss of material. The Fire Protection (B.2.1.16) program manages the aging of these materials.

2. Cementitious Fireproofing materials are fire-resistant insulation and coating materials potentially subject to cracking and loss of material. The Fire Protection (B.2.1.16) program manages the aging of these materials.

3. Aluminum Silicate is a fire barrier material potentially subject to cracking and change in material properties. The Fire Protection (B.2.1.16) program manages the aging of these materials.

4. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-15
Fuel Handling System
Summary of Aging Management Evaluation

Table 3.3.2-15 Fuel Handling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A

Table 3.3.2-15 Fuel Handling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.A5.TP-261	3.5.1-088	E, 1
			Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B1.2.TP-232	3.5.1-085	E, 1
				Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.A5.TP-261	3.5.1-088	E, 1
Crane/hoist (Auxiliary Work Platform and Jib Crane)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-15 Fuel Handling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Crane/hoist (Auxiliary Work Platform and Jib Crane)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
Crane/hoist (Fuel Prep Machine)	Structural Support	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				None	None	III.B5.T-37a	3.5.1-100	I, 2
			Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.A4.AP-130	3.3.1-025	E, 1
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
			Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B1.1.TP-10	3.5.1-090	E, 1
Crane/hoist (Reactor Service Platform)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-15 Fuel Handling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Crane/hoist (Reactor Service Platform)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
Crane/hoist (Refueling Platform)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1

Table 3.3.2-15 Fuel Handling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Crane/hoist (Refueling Platform-Mast)	Structural Support	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
			Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B1.1.TP-10	3.5.1-090	E, 1
Crane/hoist (Service Pole Caddy Platform)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
				Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-15 Fuel Handling System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Overhead Heavy Load and Light Load (Related to Fuel Handling) Systems (B.2.1.13) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.

2. The aluminum fuel prep machine components are constructed of 6061-T6 aluminum alloy which is not susceptible to stress corrosion cracking.

Table 3.3.2-16
Fuel Pool Cooling and Cleanup System
Summary of Aging Management Evaluation

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
Heat Exchanger - (Fuel Pool Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	C

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Fuel Pool Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
Pump Casing (Fuel Pool Cooling Pumps)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.A4.AP-31	3.3.1-072	A
Pump Casing (Fuel Pool F/D Holding Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Fuel Pool F/D Holding Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.A4.AP-31	3.3.1-072	A
Pump Casing (Waste Precoat Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.A4.AP-31	3.3.1-072	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
Tanks (Fuel Pool Filter Demineralizer)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
Tanks (Fuel Pool Skimmer Surge Tank)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Fuel Pool Skimmer Surge Tank)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	C
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	D
Tanks (Waste Precoat Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.A4.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B

Table 3.3.2-16 Fuel Pool Cooling and Cleanup System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

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

Table 3.3.2-17 High Pressure Service Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Shell Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tube Side Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	VII.C1.A-791	3.3.1-257	A
					One-Time Inspection (B.2.1.21)	VII.C1.A-791	3.3.1-257	A
			Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
		Stainless Steel	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.26)	VII.C1.A-791	3.3.1-257	A
					One-Time Inspection (B.2.1.21)	VII.C1.A-791	3.3.1-257	A
			Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-133	3.3.1-099	C
					One-Time Inspection (B.2.1.21)	VII.C1.AP-133	3.3.1-099	C
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
		Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-138	3.3.1-100	C
					One-Time Inspection (B.2.1.21)	VII.C1.AP-138	3.3.1-100	C

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (High Pressure Service Water Pump Motor Lube Oil Coolers) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.C1.A-417	3.3.1-096b	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
				Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.C1.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.C1.A-414	3.3.1-139	B
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RHR Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Insulated Valve Body	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3.1-126	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-198	3.3.1-109	A
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-284	3.3.1-109	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (High Pressure Service Water Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
Strainer (Element)	Filter	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 High Pressure Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-284	3.3.1-109	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 High Pressure Service Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-18
Offgas and Recombiner System
Summary of Aging Management Evaluation

Table 3.3.2-18 Offgas and Recombiner System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Condensation (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
						VIII.E.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A

Table 3.3.2-18 Offgas and Recombiner System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Tanks (Offgas Drain Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B

Table 3.3.2-18 Offgas and Recombiner System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-18 Offgas and Recombiner System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-19
Plant Equipment and Floor Drain System
Summary of Aging Management Evaluation

Table 3.3.2-19 Plant Equipment and Floor Drain System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Waste Water (External)	Long-Term Loss of Material	Bolting Integrity (B.2.1.10)	VII.E5.A-785	3.3.1-193	E, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Waste Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-728	3.3.1-085	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Piping, piping components with Internal Coatings	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E5.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E5.A-414	3.3.1-139	B
Pump Casing (Circulating Water Pump Structure Sump Pump)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.E5.A-410	3.3.1-135	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Circulating Water Pump Structure Sump Pump)	Pressure Boundary	Gray Cast Iron	Waste Water (External)	Loss of Material	Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Conveyor Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (D/G Building Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Drywell Equipment Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Drywell Floor Drains Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Floor Drain Collector Pump)	Leakage Boundary	Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Laundry Drain Tank Pump)	Leakage Boundary	Ductile Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Off Gas Stack Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (RHR Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Radwaste Building Equipment Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Radwaste Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Reactor Building Equipment Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Reactor Building Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Recombiner Building Equipment Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Recombiner Building Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Recombiner Building Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Turbine Building Equipment Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Turbine Building Floor Drain Sump Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Tanks (Floor Drain Demin)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Floor Drain Demin)	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tanks (Floor Drain Surge Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tanks (Laundry Drain Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.A-26	3.3.1-055	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-19 Plant Equipment and Floor Drain System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Bolting Integrity (B.2.1.10) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-20

Post Accident Sampling System

Summary of Aging Management Evaluation

Table 3.3.2-20 Post Accident Sampling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Heat Exchanger - (Jet Pump Sample Cooler) Tubes	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-112	3.3.1-020	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
Heat Exchanger - (PASS Liquid Sample Cooler) Tubes	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A

Table 3.3.2-20 Post Accident Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Leakage Boundary	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-20 Post Accident Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (PASS Water Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-32	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A

Table 3.3.2-20 Post Accident Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-20 Post Accident Sampling System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-21

Process Sampling System

Summary of Aging Management Evaluation

Table 3.3.2-21 Process Sampling System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-21 Process Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Titanium	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-160	3.3.1-122	A
			Treated Water (Internal)	None	None	VII.J.A-766	3.3.1-237	A
Tanks (TBCCW HX Service Water Sample Tank)	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	C

Table 3.3.2-21 Process Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (TBCCW HX Service Water Sample Tank)	Leakage Boundary	PVC	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-787c	3.3.1-253	C
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-21 Process Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-32	3.3.1-072	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-21 Process Sampling System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-22

Pump Structure Ventilation System

Summary of Aging Management Evaluation

Table 3.3.2-22 Pump Structure Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
				Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.F2.A-794	3.3.1-260	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-08	3.3.1-090	A
		Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-08	3.3.1-090	A
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-113	3.3.1-082	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F2.A-504	3.3.1-085	A

Table 3.3.2-22 Pump Structure Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flexible Connection	Pressure Boundary	Elastomer	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-22 Pump Structure Ventilation System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-23
Radiation Monitoring System
Summary of Aging Management Evaluation

Table 3.3.2-23 Radiation Monitoring System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-23 Radiation Monitoring System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-763a	3.3.1-234	A
				None	None	VII.C1.A-451a	3.3.1-189	I, 1
			Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-763a	3.3.1-234	A
				None	None	VII.C1.A-451a	3.3.1-189	I, 1
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A

Table 3.3.2-23 Radiation Monitoring System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
Pump Casing (HPSW Rad Monitor Sample Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Pump Casing (Main Stack Rad Monitor Sample Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
Tanks (HPSW Rad Monitor)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-23 Radiation Monitoring System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A

Table 3.3.2-23 Radiation Monitoring System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The filter housings are constructed of 3003 aluminum alloy which is not susceptible to stress corrosion cracking.

Table 3.3.2-24
Radwaste System
Summary of Aging Management Evaluation

Table 3.3.2-24 Radwaste System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
			Raw Water (Internal)	None	None	VII.J.AP-269	3.3.1-119	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump Casing (Chemical Waste Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump Casing (Condensate Backwash Transfer Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Condensate Decant Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Condensate Sludge Discharge Mixing Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Injection Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump Casing (RWCU Backwash Transfer Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (RWCU Backwash Transfer Pump)	Leakage Boundary	Gray Cast Iron	Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
Pump Casing (Sludge Sample Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tanks (Chemical Waste Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tanks (Filter Aid Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-416	3.3.1-138	E, 1

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Filter Aid Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-414	3.3.1-139	E, 1
Tanks (Laundry Hot Water Heater)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-270	3.3.1-088	C
Tanks (Mixing Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tanks (RWCU Filter Demin Backwash Receiving Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-416	3.3.1-138	E, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-414	3.3.1-139	E, 1

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Radwaste Bldg Personnel Decon Hot Water Heater)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-416	3.3.1-138	E, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-414	3.3.1-139	E, 1
Tanks (Waste Collector Filter Demin)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E5.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E5.A-414	3.3.1-139	B
Tanks (Waste Surge Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-24 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-272	3.3.1-095	A
					Selective Leaching (B.2.1.22)	VII.E5.A-547	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-24 Radwaste System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination. The environment is Raw Water (Potable) that does not have the potential for microbiologically-induced corrosion.

Table 3.3.2-25
Reactor Building Closed Cooling Water System
Summary of Aging Management Evaluation

Table 3.3.2-25 Reactor Building Closed Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Compressor Housing (Instrument Nitrogen Compressor)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Heat Exchanger - (Instrument Nitrogen Compressor Aftercooler) Tube Side Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	C
Heat Exchanger - (Instrument Nitrogen Compressor Aftercooler) Tubes	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Instrument Nitrogen Compressor Aftercooler) Tubes	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.F1.A-417	3.3.1-096b	E, 1
Heat Exchanger - (PASS Jet Pump and Liquid Sample Coolers) Shell Side Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
Heat Exchanger - (RBCCW Heat Exchangers) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat Exchanger - (RWCU Non-Regenerative Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	D
Heat Exchanger - (RWCU Pump Motor Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RWCU Pump Motor Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat Exchanger - (Reactor Water Sample Heat Transfer Coil) Shell Side Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
Hoses	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B
Insulated Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
		Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (RBCCW Pumps)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Tanks (RBCCW Chemical Addition Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
Tanks (RBCCW Head Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	B

Table 3.3.2-25 Reactor Building Closed Cooling Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-26

Reactor Water Cleanup System

Summary of Aging Management Evaluation

Table 3.3.2-26 Reactor Water Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Heat Exchanger - (RWCU Non-Regenerative Heat Exchanger) Tube Side Components	Leakage Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-112	3.3.1-020	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-112	3.3.1-020	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RWCU Non-Regenerative Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
Heat Exchanger - (RWCU Pump Motor Cooler) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-112	3.3.1-020	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
Heat Exchanger - (RWCU Regenerative Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-120	3.3.1-019	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RWCU Regenerative Heat Exchanger) Tube Side Components	Leakage Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-120	3.3.1-019	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-120	3.3.1-019	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-111	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 3
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
						VIII.E.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components outboard the second containment isolation valves with a diameter greater than or equal to 4" NPS	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water > 200 F (Internal)	Cracking	BWR Reactor Water Cleanup System (B.2.1.15)	VII.E3.AP-283	3.3.1-016	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-283	3.3.1-016	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3.1-126	A
Pump Casing (RWCU Filter Demineralizer Holding Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (RWCU Filter Demineralizer Precoat Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
Pump Casing (RWCU Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
Tanks (RWCU Filter Demineralizer Precoat Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (RWCU Filter Demineralizer Precoat Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 1
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)			G, 2
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-416	3.3.1-138	E, 4
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-414	3.3.1-139	E, 4
Tanks (RWCU Filter Demineralizer)	Leakage Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	D
Tanks (Slurry Prep Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	C
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	D

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water > 482 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	V.D2.E-11	3.2.1-010	E, 5
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E3.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.A-773	3.3.1-244	A
					Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B

Table 3.3.2-26 Reactor Water Cleanup System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The internal environment of condensation is associated with the air space in the RWCU Filter Demineralizer Precoat Tank. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program.

2. The internal environment of condensation is associated with the air space in the RWCU Filter Demineralizer Precoat Tank. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of material due to general, pitting, and crevice corrosion. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program.

3. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

4. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

5. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-27
Refueling Water Storage and Transfer System
Summary of Aging Management Evaluation

Table 3.3.2-27 Refueling Water Storage and Transfer System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Insulated Valve Body	Pressure Boundary	Gray Cast Iron	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.I.A-734b	3.3.1-205	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-761b	3.3.1-232	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-27 Refueling Water Storage and Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Concrete (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.A-425	3.3.1-144	A
				Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-137	3.3.1-107	A
			Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.A-425	3.3.1-144	A
				Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VII.I.AP-137	3.3.1-107	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.A-773	3.3.1-244	A

Table 3.3.2-27 Refueling Water Storage and Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Pump Casing (Refueling Water Pumps)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
Tanks (Refueling Water Storage Tank)	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Outdoor (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VII.C3.A-401	3.3.1-128	A
			Condensation (Internal)	Loss of Coating or Lining Integrity	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)			G, 1
				Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)			G, 2
			Soil (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VII.C3.A-401	3.3.1-128	A
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VII.E4.A-416	3.3.1-138	E, 3
				Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VII.E4.A-414	3.3.1-139	E, 3

Table 3.3.2-27 Refueling Water Storage and Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
					Selective Leaching (B.2.1.22)	VII.E4.AP-31	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A

Table 3.3.2-27 Refueling Water Storage and Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-27 Refueling Water Storage and Transfer System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The internal environment of condensation is associated with the air space in the Refueling Water Storage Tank. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage. This aging effect is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) aging management program which incorporates the inspection recommendations of Generic Aging Lessons Learned (GALL) Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks".

2. The internal environment of condensation is associated with the air space in the Refueling Water Storage Tank. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of material due to general, pitting, and crevice corrosion. This aging effect is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) aging management program which includes periodic visual inspection of accessible tank internal surfaces for the loss of material.

3. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-28
Safety Grade Instrument Gas System
Summary of Aging Management Evaluation

Table 3.3.2-28 Safety Grade Instrument Gas System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Hoses	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A

Table 3.3.2-28 Safety Grade Instrument Gas System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Strainer (Element)	Filter	Stainless Steel	Air - Dry (External)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.A-451a	3.3.1-189	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.F2.A-763a	3.3.1-234	A
			Gas (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A

Table 3.3.2-28 Safety Grade Instrument Gas System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.D.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.D.AP-221a	3.3.1-006	A
			Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-28 Safety Grade Instrument Gas System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-29
Service Water System
Summary of Aging Management Evaluation

Table 3.3.2-29 Service Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
			Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Heat Exchanger - (Fuel Pool Cooling Heat Exchanger) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger - (RBCCW Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (RBCCW Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger - (Radwaste Building Heating System Condensate Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tube Sheet	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-778	3.3.1-249	C
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Recirc M/G Set Fluid Coupling Oil Cooler) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (Turbine Building Closed Cooling Water Heat Exchanger) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Ductile Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
		Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.I.A-734b	3.3.1-205	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-761b	3.3.1-232	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Insulated piping, piping components	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3.1-126	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
						VII.C1.A-400	3.3.1-127	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A
		PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-787c	3.3.1-253	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
Pump Casing (Fuel Pool Service Water Booster Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Fuel Pool Service Water Booster Pump)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
					Selective Leaching (B.2.1.22)	VII.C1.A-51	3.3.1-072	A

Table 3.3.2-29 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-787c	3.3.1-253	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-29 Service Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-30
Standby Liquid Control System
Summary of Aging Management Evaluation

Table 3.3.2-30 Standby Liquid Control System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Accumulator (Standby Liquid Control N2 Accumulator)	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E4.A-416	3.3.1-138	B
				Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29)	VII.E4.A-414	3.3.1-139	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Drip Pan (Trough)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	E, 2
Gearbox (Standby Liquid Control Pump)	Pressure Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.H2.A-763a	3.3.1-234	C
				None	None	VII.E2.A-451a	3.3.1-189	I, 3
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-162	3.3.1-099	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-162	3.3.1-099	C
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Gearbox (Standby Liquid Control Pump)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	C
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-097	C
					One-Time Inspection (B.2.1.21)	VII.H2.AP-127	3.3.1-097	C
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
			Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E5.A-785	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Sodium Pentaborate Solution (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)			G, 4
				Loss of Material	One-Time Inspection (B.2.1.21)			G, 4
					Water Chemistry (B.2.1.2)			G, 4
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Sodium Pentaborate Solution (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)			G, 4
				Loss of Material	One-Time Inspection (B.2.1.21)			G, 4
					Water Chemistry (B.2.1.2)			G, 4
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
Strainer (Element)	Filter	Stainless Steel	Sodium Pentaborate Solution (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A
			Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	C
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.I.A-751b	3.3.1-222	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	C
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	D
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E2.AP-141	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
Valve Body (Class 1)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 482 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-038	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A

Table 3.3.2-30 Standby Liquid Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482 F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.3.2-30 Standby Liquid Control System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
2. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.
3. The gearbox level glass bodies are constructed of 6063-T6 aluminum alloy which is not susceptible to stress corrosion cracking.
4. The Water Chemistry (B.2.1.2) program manages the aging effects on Standby Liquid Control (SLC) system components subject to the sodium pentaborate environment by monitoring and controlling SLC poison storage tank treated water chemistry. Aging effects on carbon steel exposed to a sodium pentaborate environment are established using a treated water environment.

Table 3.3.2-31

Suppression Pool Temperature Monitoring System

Summary of Aging Management Evaluation

Table 3.3.2-31 Suppression Pool Temperature Monitoring System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-31 Suppression Pool Temperature Monitoring System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-32
Torus Water Cleanup System
Summary of Aging Management Evaluation

Table 3.3.2-32 Torus Water Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
Pump Casing (Torus Water Filter Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B

Table 3.3.2-32 Torus Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Torus Water Filter Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VII.A4.AP-31	3.3.1-072	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.A-532	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B

Table 3.3.2-32 Torus Water Cleanup System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-33

Torus Water Storage and Transfer System

Summary of Aging Management Evaluation

Table 3.3.2-33 Torus Water Storage and Transfer System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Hoses	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
			Condensation (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E4.A-504	3.3.1-085	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A

Table 3.3.2-33 Torus Water Storage and Transfer System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Torus Dewatering Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
Pump Casing (Torus Sludge Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A

Table 3.3.2-33 Torus Water Storage and Transfer System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-34
Traveling Water Screen System
Summary of Aging Management Evaluation

Table 3.3.2-34 Traveling Water Screen System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Flexible Connection	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-102	3.3.1-076	A
				Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-113	3.3.1-082	A
			Raw Water (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.AP-75	3.3.1-085	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.AP-76	3.3.1-096	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-34 Traveling Water Screen System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3.1-126	A
		Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Service Water Traveling Screen Wash Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
Traveling Screen	Filter	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-34 Traveling Water Screen System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Traveling Screen	Filter	Carbon Steel	Raw Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless Steel	Raw Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.A-532	3.3.1-193	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C1.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C1.AP-221a	3.3.1-006	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-34 Traveling Water Screen System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.3.2-35
Turbine Building Closed Cooling Water System
Summary of Aging Management Evaluation

Table 3.3.2-35 Turbine Building Closed Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Compressor Housing (Condensate Backwash System Air Compressor)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Compressor Housing (Radwaste Air Compressor)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Heat Exchanger - (Condensate Backwash System Air Compressor Aftercooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A

Table 3.3.2-35 Turbine Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Condensate Backwash System Air Compressor Aftercooler) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat Exchanger - (Condensate Backwash System Air Compressor Intercooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat Exchanger - (Radwaste Air Compressor Aftercooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat Exchanger - (Turbine Building Closed Cooling Water Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.AP-41	3.3.1-080	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	B
Insulated Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-35 Turbine Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
Insulated piping, piping components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-405a	3.3.1-132	A
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
			Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
			Lubricating Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C2.AP-133	3.3.1-099	E, 1
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B

Table 3.3.2-35 Turbine Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Lubricating Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C2.AP-138	3.3.1-100	E, 1
Pump Casing (Turbine Building Closed Cooling Water Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
Tanks (TBCCW Chemical Addition Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.D.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-35 Turbine Building Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
			Lubricating Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C2.AP-133	3.3.1-099	E, 1
		Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	B
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B.2.1.22)	VII.C2.AP-43	3.3.1-072	A
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B.2.1.22)	VII.C2.A-50	3.3.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.C2.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.C2.AP-221a	3.3.1-006	A
			Lubricating Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C2.AP-138	3.3.1-100	E, 1

Table 3.3.2-35 Turbine Building Closed Cooling Water System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-36
Water Treatment System
Summary of Aging Management Evaluation

Table 3.3.2-36 Water Treatment System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-36 Water Treatment System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-078	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.A-439	3.3.1-193	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-021	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-140	3.3.1-022	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VII.E4.AP-209a	3.3.1-004	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E4.AP-221a	3.3.1-006	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-203	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-36 Water Treatment System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Condensate System (2.3.4.1)
- Condensate Storage System (2.3.4.2)
- Feedwater System (2.3.4.3)
- Main Condenser System (2.3.4.4)
- Main Steam System (2.3.4.5)

3.4.2 RESULTS

The following tables summarize the results of the aging management review for Steam and Power Conversion Systems.

Table 3.4.2-1 Condensate System - Summary of Aging Management Evaluation

Table 3.4.2-2 Condensate Storage System - Summary of Aging Management Evaluation

Table 3.4.2-3 Feedwater System - Summary of Aging Management Evaluation

Table 3.4.2-4 Main Condenser System - Summary of Aging Management Evaluation

Table 3.4.2-5 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 System

Materials

The materials of construction for the Condensate System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Glass

Environments

The Condensate System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Condensate System components require management:

- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Condensate System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.4.2.1.2 Condensate Storage System

Materials

The materials of construction for the Condensate Storage System components are:

- Carbon Steel
- Carbon Steel (with internal coating)
- Carbon and Low Alloy Steel Bolting
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The Condensate Storage System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Condensation
- Soil
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Condensate Storage System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Condensate Storage System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.28)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)
- Selective Leaching (B.2.1.22)
- Water Chemistry (B.2.1.2)

3.4.2.1.3 Feedwater System

Materials

The materials of construction for the Feedwater System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Stainless Steel

Environments

The Feedwater System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Condensation
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Feedwater System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Feedwater System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)

- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.1.4 Main Condenser System

Materials

The materials of construction for the Main Condenser System components are:

- Aluminum Alloy
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Stainless Steel
- Titanium

Environments

The Main Condenser 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 Main Condenser System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Main Condenser System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

(B.2.1.25)

- One-Time Inspection (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.4.2.1.5 Main Steam System

Materials

The materials of construction for the Main Steam System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Stainless Steel

Environments

The Main Steam System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation
- Steam
- Treated Water
- Treated Water > 140 F

Aging Effects Requiring Management

The following aging effects associated with the Main Steam System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Main Steam System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.23)

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- One-Time Inspection (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Steam and Power Conversion Systems, those programs are addressed in the following subsections.

3.4.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Table 3.4.1 Item Number 3.4.1-001: This item evaluates steel piping, piping components exposed to any environment for cumulative fatigue damage due to fatigue. Cumulative fatigue damage of steel piping, piping components is evaluated and dispositioned as a TLAA for the Feedwater System and Main Steam System as discussed in Section 4.3.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor stainless steel (SS) piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain *contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific operating experience (OE) and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.4.1 Item Number 3.4.1-002: This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are no stainless steel tanks in the Steam and Power Conversion Systems. There are no stainless steel piping, piping components exposed to the air-indoor controlled environment in the Steam and Power Conversion Systems. Plant-specific OE associated with stainless steel components in the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for stainless steel components in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in stainless steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.4.1 Item Number 3.4.1-074: Not applicable. There are no stainless steel underground piping, piping components or tanks in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-100: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-104: This item evaluates cracking due to SCC in insulated stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are no insulated stainless steel tanks in the Steam and Power Conversion Systems. There are no insulated stainless steel piping or piping components exposed to air-indoor controlled, air-indoor uncontrolled, or condensation environments in the Steam and Power Conversion Systems. 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 air-outdoor environment has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at PBAPS for insulated stainless steel components in the air-outdoor environment indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC has not occurred. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of cracking is not occurring in insulated stainless steel piping and piping components exposed to air-outdoor. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the *insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.4.1 Item Number 3.4.1-003: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components, and tanks exposed to air or condensation environments. There are no stainless steel or nickel alloy tanks, or nickel alloy piping, piping components in the Steam and Power Conversion Systems. There are no stainless steel piping, piping components exposed to air-indoor controlled in the Steam and Power Conversion Systems. Plant-specific operating experience (OE) associated with stainless steel components in the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for stainless steel components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.4.1 Item Number 3.4.1-095: Not applicable. There are no stainless steel or nickel alloy underground piping, piping components, or tanks in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-098: Not applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-103: This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel or nickel alloy piping, piping components, and tanks exposed to air and condensation environments. There are no insulated stainless steel or nickel alloy tanks or insulated nickel alloy piping, piping components in the Steam and Power Conversion Systems. There are no insulated stainless steel piping, piping components exposed to air-indoor controlled, air-indoor uncontrolled, or condensation environments in the Steam and Power Conversion Systems. 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 air-outdoor has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for insulated stainless steel components in this environment indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in loss of material has not occurred. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in insulated stainless steel piping and piping components exposed to air-outdoor. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3.

3.4.2.2.5 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, section B.1.4.

3.4.2.2.6 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual); (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of *inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.*

Table 3.4.1 Item Number 3.4.1-061: Not Applicable. This item evaluates loss of material due to recurring internal corrosion of metallic piping, piping components, and tanks exposed to raw water and waste water. There are no components exposed to waste water in the Steam and Power Conversion Systems. The titanium heat exchanger tubes and tube sheet are the only components exposed to raw water in the Steam and Power Conversion Systems. Plant-specific OE associated with loss of material of metallic components in the Steam and Power Conversion Systems has been evaluated over the period from 2003 to 2017 to identify instances of loss of material due to recurring internal corrosion in raw water and other internal environments. The OE review did not identify any components within the Steam and Power Conversion Systems where the frequency and severity for loss of material met the thresholds discussed above that would require augmenting the aging management recommendations in the GALL-SLR Report to manage loss of material due to recurring internal corrosion.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>Susceptible Material</u>: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*

- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an *acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.4.1 Item Number 3.4.1-102: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-105: Not applicable. There are no insulated aluminum alloy piping, piping components, or tanks in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-109: This item evaluates cracking due to SCC in aluminum alloy piping, piping components, and tanks exposed to air, condensation, raw water, and waste water environments. There are no aluminum alloy tanks in the Steam and Power Conversion Systems. There are no aluminum alloy piping, piping components exposed to the air-indoor controlled, air-outdoor, condensation, raw water, or waste water environments in the Steam and Power Conversion Systems. The aluminum alloy piping and piping components exposed to air-indoor uncontrolled in the Steam and Power Conversion Systems includes the Main Condenser rupture disks. These rupture disks are constructed of 3003 series aluminum alloy which is not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

Table 3.4.1 Item Number 3.4.1-112: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in 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 high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, *as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.*

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Table 3.4.1 Item Number 3.4.1-051: Not applicable. There are no steel piping or piping components exposed to concrete in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-082: This item evaluates stainless steel piping, piping components exposed to the concrete environment. Cracking due to SCC and loss of material are not considered to be applicable aging effects for portions of the stainless steel piping, piping components exposed to concrete that is outdoors and above ground level in the Condensate Storage System since: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. Portions of the stainless steel piping, piping components in the Condensate Storage System that are exposed to concrete and are outdoors and below ground level are susceptible to cracking due to SCC because they are potentially exposed to groundwater, and are addressed by Item Number 3.4.1-072.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition *of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50^{th} and 60^{th} year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Table 3.4.1 Item Numbers 3.4.1-035: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy piping, piping components, and tanks exposed to air or condensation environments. There are no aluminum alloy tanks in the Steam and Power Conversion Systems. There are no aluminum alloy piping or piping components exposed to the air-indoor controlled, air-outdoor, or condensation environments in the Steam and Power Conversion Systems. Plant-specific OE associated with aluminum alloy components in the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled environment has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at PBAPS for aluminum alloy components in this environment, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection (B.2.1.21) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in aluminum piping, piping components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.21) program is described in Appendix B.

Table 3.4.1 Item Number 3.4.1-094: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-097: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-119: Not applicable. There are no insulated aluminum alloy piping, piping components, or tanks in the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4.1-120: Not applicable. There are no aluminum alloy piping, piping components, or tanks exposed to raw water or waste water in 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 Analyses
    - Section 4.3.2, ASME Section III, Class 1 Fatigue Analyses
    - Section 4.3.4, ASME Section III, Class 2, Class 3, and ANSI B31.1 Allowable Stress Analyses
    - Section 4.3.5, Environmental Fatigue Analyses for RPV and Class 1 Piping
- Section 4.7, Other Plant-Specific Analyses
    - Section 4.7.4, Fracture Mechanics of ISI-Reportable Indications for Group I Piping: As-Forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT

3.4.3 CONCLUSION

The Steam and Power Conversion System components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Steam and Power Conversion System components are identified in the summaries in Section 3.4.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Steam and Power Conversion System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.4.2.2.1.
3.4.1-002	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the stainless steel piping, piping components exposed to air - indoor uncontrolled, air - outdoor, and condensation in the Condensate Storage System, Feedwater System, Main Condenser System, and Main Steam System. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-003	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the stainless steel piping, piping components exposed to air - indoor uncontrolled, air - outdoor, and condensation in the Condensate Storage System, Feedwater System, Main Condenser System, and Main Steam System. See Subsection 3.4.2.2.3.
3.4.1-004	PWR Only				
3.4.1-005	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel heat exchanger components, piping, piping components exposed to steam and treated water in the Auxiliary Steam System, Feedwater System, Main Condenser System, Main Steam System, Offgas and Recombiner System, and Reactor Water Cleanup System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-006	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor uncontrolled and air - outdoor in the Condensate Storage System, Condensate System, Feedwater System, Main Condenser System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
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 are no high-strength steel closure bolting exposed to soil or underground in Steam and Power Conversion Systems. High-strength steel closure bolting in the Main Steam System exposed to air – indoor uncontrolled is addressed by Item Number 3.1.1-062.
3.4.1-008	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-009	Steel, stainless steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor uncontrolled and air - outdoor in the Condensate Storage System, Condensate System, Feedwater System, Main Condenser System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.4.1-010	This Item Number is not used in NUREG-2192.				
3.4.1-011	Stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP-XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel piping, piping components exposed to treated water > 140 F in the Condensate Storage System, Feedwater System, Main Condenser System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no steel tanks exposed to treated water in Steam and Power Conversion Systems. The carbon steel tanks within the Condensate Storage System are lined, therefore loss of material is addressed by Item Number 3.4.1-067.
3.4.1-013	This Item Number is not used in NUREG-2192.				
3.4.1-014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel and gray cast iron piping, piping components exposed to steam and treated water in the Condensate Storage System, Condensate System, Feedwater System, Main Condenser System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to treated water in the Main Condenser System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-016	Copper alloy, aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the aluminum alloy and copper alloy piping, piping components exposed to treated water in the Main Condenser System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-017	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer of the copper alloy heat exchanger tubes exposed to treated water in the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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 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, piping components exposed to raw water in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-021	This Item Number is not used in NUREG-2192.				
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 stainless steel, copper alloy, or steel heat exchanger tubes exposed to raw water in 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, piping components exposed to closed cycle cooling water >140 F in Steam and Power Conversion Systems.
3.4.1-024	This Item Number is not used in NUREG-2192.				
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 Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-026	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 or piping, piping components exposed to closed cycle cooling water in Steam and Power Conversion Systems.
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, piping components exposed to closed cycle cooling water in 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 tubes exposed to closed cycle cooling water in Steam and Power Conversion Systems.
3.4.1-029	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-030	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program will be used to manage loss of material of the carbon steel tanks exposed to air - outdoor and soil in the Condensate Storage System.
3.4.1-031	This Item Number is not used in NUREG-2192.				
3.4.1-032	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components exposed to soil in Steam and Power Conversion Systems.
3.4.1-033	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, closed-cycle cooling water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching (B.2.1.22) program will be used to manage loss of material of gray cast iron piping, piping components exposed to treated water in the Condensate Storage System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-034	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components and piping, piping components exposed to air - indoor uncontrolled and air - outdoor in the Condensate Storage System, Condensate System, Feedwater System, Main Condenser System, and Main Steam System.
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	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Main Condenser System. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel piping, piping components exposed to air – outdoor internal environment in Steam and Power Conversion Systems.
3.4.1-037	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage loss of material of the carbon steel piping, piping components exposed to condensation in the Condensate System, Feedwater System, and Main Steam System.
3.4.1-038	PWR Only				
3.4.1-039	This Item Number is not used in NUREG-2192.				
3.4.1-040	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no steel piping, piping components exposed to lubricating oil in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-041	PWR Only				
3.4.1-042	PWR Only				
3.4.1-043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no copper alloy piping, piping components exposed to lubricating oil in Steam and Power Conversion Systems.
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.2.1.26) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the stainless steel heat exchanger components exposed to lubricating oil in the Core Spray System.
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 exposed to lubricating oil in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-046	PWR Only				
3.4.1-047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage loss of material of the stainless steel piping, piping components exposed to concrete and soil in the Condensate Storage System.
3.4.1-048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no nickel alloy piping, piping components, tanks, or closure bolting exposed to soil or concrete in Steam and Power Conversion Systems.
3.4.1-049	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-050	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, concrete or underground in Steam and Power Conversion Systems. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program will be used to manage loss of material of the carbon steel tanks exposed to soil in the Condensate Storage System as addressed by Item Number 3.4.1-030.
3.4.1-050a	This Item Number is not used in NUREG-2192.				
3.4.1-051	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. See Subsection 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, piping components exposed to gas in the Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-053	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, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion Systems.
3.4.1-054	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
3.4.1-055	Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191.
3.4.1-056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not Applicable. There are no PVC piping, piping components exposed to air – indoor uncontrolled or condensation 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.
3.4.1-059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not Applicable. There are no steel piping, piping components exposed to air – indoor controlled or gas in the Steam and Power Conversion 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. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel and stainless steel piping, piping components exposed to steam and treated water in the Condensate System, Feedwater System, Main Condenser System, and Main Steam System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-061	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	Not Applicable. See Subsection 3.4.2.2.6.
3.4.1-062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water in Steam and Power Conversion Systems. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program will be used to manage loss of material of the carbon steel tanks with internal coating exposed to treated water in the Condensate Storage System as addressed by Item Number 3.4.1-067.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.24) program will be used to manage loss of material of the insulated carbon steel and gray cast iron piping, piping components exposed to air - outdoor in the Condensate Storage System.
3.4.1-064	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. The "External Surfaces Monitoring of Mechanical Components" (B.2.1.24) program will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air as addressed by Item Number 3.3.1-182.
3.4.1-065	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-066	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	The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel tanks with internal coating exposed to treated water in the Condensate Storage System.
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	The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program has been substituted and will be used to manage loss of material of the carbon steel tanks with internal coating exposed to treated water in the Condensate Storage System.
3.4.1-068	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components with internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, or waste water in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-069	This Item Number is not used in NUREG-2192.				
3.4.1-070	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There are no 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 Steam and Power Conversion Systems.
3.4.1-071	This Item Number is not used in NUREG-2192.				
3.4.1-072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.1.28) program will be used to manage cracking of the stainless steel piping, piping components exposed to concrete and soil in the Condensate Storage System. Cracking due to SCC in steel is not an applicable aging effect/mechanism since soil and concrete are not a carbonate/bicarbonate environment.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the stainless steel closure bolting exposed to air - indoor uncontrolled in the Condensate Storage System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
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	Not Applicable. See Subsection 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 stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air, or condensation in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-076	This Item Number is not used in NUREG-2192.				
3.4.1-077	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air or condensation in 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 piping, piping components, or seals exposed to air or condensation in Steam and Power Conversion Systems.
3.4.1-079	This Item Number is not used in NUREG-2192.				
3.4.1-080	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage long-term loss of material of the carbon steel and gray cast iron heat exchanger components and piping, piping components exposed to treated water in the Condensate Storage System, Condensate System, Feedwater System, Main Condenser System, and Main Steam System.
3.4.1-082	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. See Subsection 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 Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not Applicable. There are no nickel alloy piping, piping components exposed to steam in Steam and Power Conversion Systems. Loss of material of the stainless steel piping, piping components exposed steam in the Main Steam System is addressed by Item Number 3.1.1-079.
3.4.1-085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel piping, piping components exposed to treated water in the Condensate Storage System, Feedwater System, Main Condenser System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes internal to components exposed to air or condensation in Steam and Power Conversion Systems.
3.4.1-087	This Item Number is not used in NUREG-2192.				
3.4.1-088	This Item Number is not used in NUREG-2192.				
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, piping components exposed to raw water in 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 exposed to raw water in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-091	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 components exposed to raw water in 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, piping components exposed to soil in Steam and Power Conversion Systems.
3.4.1-093	This Item Number is not used in NUREG-2192.				
3.4.1-094	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 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 AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Steam and Power Conversion Systems.
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	Not Applicable. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-098	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	Not Applicable. See Subsection 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 AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in Steam and Power Conversion Systems.
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	Not Applicable. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-101	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 AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in 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	Not Applicable. See Subsection 3.4.2.2.7.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material of the insulated stainless steel piping, piping components exposed to air - outdoor in the Condensate Storage System. See Subsection 3.4.2.2.3.
3.4.1-104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking of the insulated stainless steel piping, piping components exposed to air - outdoor in the Condensate Storage System. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 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	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air or condensation in Steam and Power Conversion Systems.
3.4.1-107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) tanks exposed to air or condensation in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-108	This Item Number is not used in NUREG-2192.				
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	Not applicable. See Subsection 3.4.2.2.7.
3.4.1-110	This Item Number is not used in NUREG-2192.				
3.4.1-111	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-112	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	Not Applicable. See Subsection 3.4.2.2.7.
3.4.1-113	This Item Number is not used in NUREG-2192.				
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	Titanium heat exchanger tubes exposed to treated water in the Main Condenser System only have an intended function of holdup, therefore the aging effects of cracking due to SCC and reduction of heat transfer due to fouling are not managed.
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	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed cycle cooling water in Steam and Power Conversion Systems.
3.4.1-117	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no aluminum piping, piping components or tanks exposed to soil or concrete in Steam and Power Conversion Systems.
3.4.1-118	This Item Number is not used in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-119	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	Not Applicable. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-120	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes	Not Applicable. See Subsection 3.4.2.2.9.
3.4.1-121	This Item Number is not used in NUREG-2192.				
3.4.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air in Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-123	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 Steam and Power Conversion Systems.
3.4.1-124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There are no PVC piping, piping components, or tanks exposed to concrete in the Steam and Power Conversion Systems.
3.4.1-125	PVC piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no PVC piping, piping components, or tanks exposed to soil in 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 (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to closed cycle cooling water in the Steam and Power Conversion Systems.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, or tanks 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 piping, piping components exposed to concrete in the Steam and Power Conversion Systems.
3.4.1-129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no copper alloy piping, piping components exposed to soil or underground in 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.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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program will be used to manage cracking of the titanium heat exchanger components exposed to raw water in the Main Condenser System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-131	PWR Only				
3.4.1-132	PWR Only				
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 piping, piping components exposed to raw water in 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	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in Steam and Power Conversion Systems. The titanium tubes in the Main Condenser System are ASTM Grade 2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-135	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 piping, piping components, ducting, ducting components, or seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil in Steam and Power Conversion Systems.

Table 3.4.2-1
Condensate System
Summary of Aging Management Evaluation

Table 3.4.2-1 Condensate System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
Piping elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
			Condensation (Internal)	None	None	VIII.I.SP-68	3.4.1-055	A
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.SP-60	3.4.1-037	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-1 Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.SP-60	3.4.1-037	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B

Table 3.4.2-1 Condensate System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.4.2-2
Condensate Storage System
Summary of Aging Management Evaluation

Table 3.4.2-2 Condensate Storage System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VIII.H.S-421	3.4.1-073	B
				Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
Insulated Valve Body	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-402a	3.4.1-063	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
		Gray Cast Iron	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-402a	3.4.1-063	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B

Table 3.4.2-2 Condensate Storage System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated Valve Body	Pressure Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.1.22)	VIII.E.SP-27	3.4.1-033	A
		Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.H.S-452b	3.4.1-104	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.H.S-451b	3.4.1-103	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
	Structural Integrity (Attached)	Gray Cast Iron	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-402a	3.4.1-063	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
					Selective Leaching (B.2.1.22)	VIII.E.SP-27	3.4.1-033	A
		Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.H.S-452b	3.4.1-104	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.H.S-451b	3.4.1-103	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-402a	3.4.1-063	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A

Table 3.4.2-2 Condensate Storage System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
Insulated piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.H.S-452b	3.4.1-104	A
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.H.S-451b	3.4.1-103	A
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
Insulated piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Insulated piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.H.S-452b	3.4.1-104	A
Insulated piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.H.S-451b	3.4.1-103	A
Insulated piping, piping components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
Insulated piping, piping components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
Piping, piping components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A
Piping, piping components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B

Table 3.4.2-2 Condensate Storage System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A
			Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A
			Concrete (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.S-420	3.4.1-072	A, 4
				Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.SP-145	3.4.1-047	A, 4
				None	None	VIII.I.SP-13	3.4.1-082	A, 5
			Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.S-420	3.4.1-072	A
				Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.SP-145	3.4.1-047	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A

Table 3.4.2-2 Condensate Storage System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
	Structural Integrity (Attached)	Stainless Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.S-420	3.4.1-072	A
				Loss of Material	Buried and Underground Piping and Tanks (B.2.1.28)	VIII.H.SP-145	3.4.1-047	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Outdoor (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VIII.E.SP-115	3.4.1-030	A
			Condensation (Internal)	Loss of Coating or Lining Integrity	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)			G, 1
				Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)			G, 2
			Soil (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VIII.E.SP-115	3.4.1-030	A
			Treated Water (Internal)	Loss of Coating or Lining Integrity	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VIII.E.S-401	3.4.1-066	E, 3
				Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18)	VIII.E.S-414	3.4.1-067	E, 3
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A

Table 3.4.2-2 Condensate Storage System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
		Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
					Selective Leaching (B.2.1.22)	VIII.E.SP-27	3.4.1-033	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B

Table 3.4.2-2 Condensate Storage System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The internal environment of condensation is associated with the air space in the Condensate Storage Tanks. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage. This aging effect is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program which incorporates the inspection recommendations of Generic Aging Lessons Learned (GALL) Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks".

2. The internal environment of condensation is associated with the air space in the Condensate Storage Tanks. The aging effect on carbon steel (with internal coating) with an internal environment of condensation includes the loss of material due to general, pitting, and crevice corrosion. This aging effect is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program which includes periodic visual inspection of accessible tank internal surfaces for the loss of material.

3. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

4. Cracking due to SCC and loss of material are applicable aging effects since the piping is potentially exposed to groundwater.

Table 3.4.2-2 Condensate Storage System (Continued)

Plant Specific Notes: (continued)

5. Cracking due to SCC and loss of material are not considered to be applicable aging effects for the portion of the stainless steel piping, piping components exposed to concrete that is outdoors and above ground level since: (a) attributes of the concrete meet the guidance of American Concrete Institute (ACI) 318 for low water-to-cement ratio, low permeability, and adequate air entrainment; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater.

Table 3.4.2-3

Feedwater System

Summary of Aging Management Evaluation

Table 3.4.2-3 Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
Piping, piping components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.SP-60	3.4.1-037	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
						VIII.D2.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.D2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-127a	3.4.1-003	A
			Condensation (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.D2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Cumulative Fatigue Damage	TLAA	V.D1.E-13	3.2.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-085	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
						VIII.D2.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.D2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-127a	3.4.1-003	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
						VIII.D2.S-16	3.4.1-005	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4.1-060	A
						VIII.D2.S-16	3.4.1-005	A
Pump Casing (Reactor Feed Pumps)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.D2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-127a	3.4.1-003	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.D2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B

Table 3.4.2-3 Feedwater System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.4.2-4
Main Condenser System
Summary of Aging Management Evaluation

Table 3.4.2-4 Main Condenser System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
Expansion Joint	Holdup	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
Heat Exchanger - (Main Condenser) Tube Sheet	Holdup	Titanium	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.S-478b	3.4.1-130	A
			Treated Water (External)	None	None	VIII.I.S-463	3.4.1-115	A
Heat Exchanger - (Main Condenser) Tubes	Holdup	Titanium	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.C1.A-736	3.3.1-207	A
			Treated Water (External)	None	None	VIII.E.S-462	3.4.1-114	I, 1

Table 3.4.2-4 Main Condenser System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - (Main Condenser, Feedwater Heaters, and Drain Coolers) Shell Side Components	Holdup	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.E.S-16	3.4.1-005	C
Piping, piping components	Holdup	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
						VIII.E.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-127a	3.4.1-003	A

Table 3.4.2-4 Main Condenser System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Holdup	Stainless Steel	Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
Rupture Disks	Holdup	Aluminum Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-147a	3.4.1-035	A
				None	None	VIII.E.S-457b	3.4.1-109	I, 2
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-90	3.4.1-016	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
		Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B.2.1.2)	VIII.A.SP-101	3.4.1-016	B
Turbine Casings	Holdup	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.S-432	3.4.1-081	A

Table 3.4.2-4 Main Condenser System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Turbine Casings	Holdup	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-014	C
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	D

Table 3.4.2-4 Main Condenser System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The component performs an intended function of holdup only and therefore, the aging effects of cracking and reduction of heat transfer due to fouling are not applicable.

2. The rupture disks are constructed of 3003 aluminum alloy which is not susceptible to stress corrosion cracking.

Table 3.4.2-5

Main Steam System

Summary of Aging Management Evaluation

Table 3.4.2-5 Main Steam System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Accumulator (MSIV Accumulators)	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
				Cumulative Fatigue Damage, Cracking	TLAA	IV.C1.RP-44	3.1.1-011	A, 1
				Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
				Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
Flow Device (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Pressure Boundary	Carbon Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
	Throttle	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
		Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A, 2
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B, 2

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Throttle	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Piping, piping components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
						VIII.B2.S-15	3.4.1-005	A

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
						VIII.E.S-16	3.4.1-005	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Condensation (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.SP-60	3.4.1-037	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
						VIII.B2.S-15	3.4.1-005	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4.1-060	A
						VIII.E.S-16	3.4.1-005	A
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
	Structural Integrity (Attached)	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1.1-110	A
						IV.C1.R-23	3.1.1-060	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1.1-110	A
						IV.C1.R-23	3.1.1-060	A

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-034	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.E.SP-60	3.4.1-037	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
			Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.S-432	3.4.1-081	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
		Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	A
			Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
			Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.B2.SP-118a	3.4.1-002	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-127a	3.4.1-003	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B

Table 3.4.2-5 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	IV.C1.R-431	3.1.1-124	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Long-Term Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-448	3.1.1-133	A
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-014	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.21)	V.D2.EP-103b	3.2.1-007	A
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.R-452a	3.1.1-136	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
			Treated Water > 140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
					Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-079	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.4.2-5 Main Steam System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

2. The internal venturi section of each main steam line flow restrictor is fabricated from centrifugally cast low molybdenum content SA-351 Type CF8 CASS material. Therefore, these components are not susceptible to loss of fracture toughness due to thermal aging embrittlement.

3. The TLAA designation for the Unit 3 Main Steam Line Elbow near Weld 1-B-3BC-LDO fatigue is evaluated in Section 4.7.

3.5 AGING MANAGEMENT OF CONTAINMENTS, STRUCTURES AND COMPONENT SUPPORTS

3.5.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.4, Scoping and Screening Results: Structures, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Administration Building and Shop (2.4.1)
- Boiler House (2.4.2)
- Circulating Water Pump Structure (2.4.3)
- Component Supports (2.4.4)
- Containment Structure (2.4.5)
- Dewatering Building (2.4.6)
- Diesel Generator Building (2.4.7)
- Electrical and Instrumentation Enclosures and Raceways (2.4.8)
- Emergency Cooling Tower and Reservoir (2.4.9)
- Hazard Barriers and Elastomers (2.4.10)
- Insulation (2.4.11)
- Miscellaneous Steel (2.4.12)
- Nitrogen Storage Building (2.4.13)
- Outdoor Electric Switchgear, North Substation (2.4.14)
- Radwaste Building and Reactor Auxiliary Bay (2.4.15)
- Reactor Building (2.4.16)
- Recombiner Building (2.4.17)
- Stack (2.4.18)
- Station Blackout Structure and Foundations (2.4.19)
- Turbine Building and Main Control Room Complex (2.4.20)
- Watertight Dikes (2.4.21)
- Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (2.4.22)

3.5.2 RESULTS

The following tables summarize the results of the aging management review for Structures and Component Supports.

Table 3.5.2-1 Administration Building and Shop - Summary of Aging Management Evaluation

Table 3.5.2-2 Boiler House - Summary of Aging Management Evaluation

Table 3.5.2-3 Circulating Water Pump Structure - Summary of Aging Management Evaluation

Table 3.5.2-4 Component Supports - Summary of Aging Management Evaluation

Table 3.5.2-5 Containment Structure - Summary of Aging Management Evaluation

Table 3.5.2-6 Dewatering Building - Summary of Aging Management Evaluation

Table 3.5.2-7 Diesel Generator Building - Summary of Aging Management Evaluation

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways - Summary of Aging Management Evaluation

Table 3.5.2-9 Emergency Cooling Tower and Reservoir - Summary of Aging Management Evaluation

Table 3.5.2-10 Hazard Barriers and Elastomers - Summary of Aging Management Evaluation

Table 3.5.2-11 Insulation - Summary of Aging Management Evaluation

Table 3.5.2-12 Miscellaneous Steel - Summary of Aging Management Evaluation

Table 3.5.2-13 Nitrogen Storage Building - Summary of Aging Management Evaluation

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation - Summary of Aging Management Evaluation

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay - Summary of Aging Management Evaluation

Table 3.5.2-16 Reactor Building - Summary of Aging Management Evaluation

Table 3.5.2-17 Recombiner Building - Summary of Aging Management Evaluation

Table 3.5.2-18 Stack - Summary of Aging Management Evaluation

Table 3.5.2-19 Station Blackout Structure and Foundations - Summary of Aging Management Evaluation

Table 3.5.2-20 Turbine Building and Main Control Room Complex - Summary of Aging Management Evaluation

Table 3.5.2-21 Watertight Dikes - Summary of Aging Management Evaluation

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) - Summary of Aging Management Evaluation

3.5.2.1 <u>Materials, Environments, Aging Effects Requiring Management And Aging Management Programs</u>

3.5.2.1.1 Administration Building and Shop

Materials

The materials of construction for the Administration Building and Shop components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete

Environments

The Administration Building and Shop components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Administration Building and Shop components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking

- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Administration Building and Shop components:

- Masonry Walls (B.2.1.33)
- Structures Monitoring (B.2.1.34)

3.5.2.1.2 Boiler House

Materials

The materials of construction for the Boiler House components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Reinforced concrete

Environments

The Boiler House components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Boiler House components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Boiler House components:

- Structures Monitoring (B.2.1.34)

3.5.2.1.3 Circulating Water Pump Structure

Materials

The materials of construction for the Circulating Water Pump Structure components are:

- Bronze Bolting
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Copper Alloy with Greater Than 15% Zinc
- Ductile Iron
- Galvanized Steel
- Gray Cast Iron
- Reinforced concrete
- Stainless Steel

Environments

The Circulating Water Pump Structure components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Circulating Water Pump Structure components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength

- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water Pump Structure components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)
- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Selective Leaching (B.2.1.22)
- Structures Monitoring (B.2.1.34)

3.5.2.1.4 Component Supports

Materials

The materials of construction for the Component Supports components are:

- Aluminum
- Aluminum Bolting
- Brass Bolting
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Elastomer
- Galvanized Steel
- Galvanized Steel Bolting
- Grout
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Lubrite
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Component Supports components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Component Supports components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Loss of Material
- Loss of Mechanical Function
- Loss of Preload
- Reduction in Concrete Anchor Capacity
- Reduction or Loss of Isolation Function

Aging Management Programs

The following aging management programs manage the aging effects for the Component Supports components:

- ASME Section XI, Subsection IWF (B.2.1.31)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)
- Water Chemistry (B.2.1.2)

3.5.2.1.5 Containment Structure

Materials

The materials of construction for the Containment Structure components are:

- Carbon Steel
- Carbon Steel; Dissimilar Metal Welds
- Carbon and Low Alloy Steel Bolting
- Coatings
- Elastomer

- Galvanized Steel
- Galvanized Steel Bolting
- Grout
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Containment Structure components are exposed to the following environments:

- 10 CFR 50.49 EQ Environments
- Air - Indoor Uncontrolled
- Concrete
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Containment Structure components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Cracking, Spalling, Corrosion of Rebar
- Cumulative Fatigue Damage
- Loss of Coating or Lining Integrity
- Loss of Leaktightness
- Loss of Material
- Loss of Mechanical Function
- Loss of Preload
- Loss of Sealing
- Reduction of Strength; Loss of Mechanical Properties
- Various Aging Effects

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Structure components:

- 10 CFR Part 50, Appendix J (B.2.1.32)
- ASME Section XI, Subsection IWE (B.2.1.30)

- Environmental Qualification of Electric Equipment (B.3.1.3)
- One-Time Inspection (B.2.1.21)
- Protective Coating Monitoring and Maintenance (B.2.1.36)
- Structures Monitoring (B.2.1.34)
- TLAA

3.5.2.1.6 Dewatering Building

Materials

The materials of construction for the Dewatering Building components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete

Environments

The Dewatering Building components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Dewatering Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Dewatering Building components:

- Masonry Walls (B.2.1.33)
- Structures Monitoring (B.2.1.34)

3.5.2.1.7 Diesel Generator Building

Materials

The materials of construction for the Diesel Generator Building components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Reinforced concrete

Environments

The Diesel Generator Building components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Diesel Generator Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel Generator Building components:

- Structures Monitoring (B.2.1.34)

3.5.2.1.8 Electrical and Instrumentation Enclosures and Raceways

Materials

The materials of construction for the Electrical and Instrumentation Enclosures and Raceways components are:

- Aluminum
- Aluminum Bolting
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Galvanized Steel Bolting
- Glass
- Stainless Steel Bolting

Environments

The Electrical and Instrumentation Enclosures and Raceways components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Electrical and Instrumentation Enclosures and Raceways components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical and Instrumentation Enclosures and Raceways components:

- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.9 Emergency Cooling Tower and Reservoir

Materials

The materials of construction for the Emergency Cooling Tower and Reservoir components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Ceramic Tile
- Concrete Block
- Galvanized Steel
- Gray Cast Iron
- PVC
- Reinforced concrete

Environments

The Emergency Cooling Tower and Reservoir components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Emergency Cooling Tower and Reservoir components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Flow Blockage
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload
- Reduction in Impact Strength

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Cooling Tower and Reservoir components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)
- Masonry Walls (B.2.1.33)
- Selective Leaching (B.2.1.22)
- Structures Monitoring (B.2.1.34)

3.5.2.1.10 Hazard Barriers and Elastomers

Materials

The materials of construction for the Hazard Barriers and Elastomers components are:

- Aluminum
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Elastomer
- Fiberglass
- Galvanized Steel
- Glass
- Grout
- Stainless Steel

Environments

The Hazard Barriers and Elastomers components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Treated Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Hazard Barriers and Elastomers components require management:

- Cracking
- Cracking, Blistering, Loss of Material
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload
- Loss of Sealing

Aging Management Programs

The following aging management programs manage the aging effects for the Hazard Barriers and Elastomers components:

- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.11 Insulation

Materials

The materials of construction for the Insulation components are:

- Aluminum
- Calcium Silicate
- Caulking and Lagging Adhesive
- Cellular Glass
- Fiberglass
- Foamed Plastic
- Galvanized Steel
- Insulation Cement and Finishing Cement
- Mineral Fiber
- Plastic Mastic Jacketing
- Silicone
- Stainless Steel
- Stainless Steel (Mirror Insulation)

Environments

The Insulation components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Insulation components require management:

- Cracking
- Loss of Material
- Reduced Thermal Insulation Resistance

Aging Management Programs

The following aging management programs manage the aging effects for the Insulation components:

- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- One-Time Inspection (B.2.1.21)

3.5.2.1.12 Miscellaneous Steel

Materials

The materials of construction for the Miscellaneous Steel components are:

- Aluminum
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Ductile Iron
- Galvanized Steel
- Galvanized Steel Bolting
- Stainless Steel

Environments

The Miscellaneous Steel components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Miscellaneous Steel components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Miscellaneous Steel components:

- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.13 Nitrogen Storage Building

Materials

The materials of construction for the Nitrogen Storage Building components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Reinforced concrete

Environments

The Nitrogen Storage Building components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Nitrogen Storage Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material

- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Nitrogen Storage Building components:

- Structures Monitoring (B.2.1.34)

3.5.2.1.14 Outdoor Electric Switchgear, North Substation

Materials

The materials of construction for the Outdoor Electric Switchgear, North Substation components are:

- Aluminum
- Aluminum Bolting
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Galvanized Steel Bolting
- Reinforced concrete

Environments

The Outdoor Electric Switchgear, North Substation components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Outdoor Electric Switchgear, North Substation components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material

- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Outdoor Electric Switchgear, North Substation components:

- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.15 Radwaste Building and Reactor Auxiliary Bay

Materials

The materials of construction for the Radwaste Building and Reactor Auxiliary Bay components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete
- Stainless Steel Bolting

Environments

The Radwaste Building and Reactor Auxiliary Bay components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Radwaste Building and Reactor Auxiliary Bay components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking

- Loss of Mechanical Function
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Radwaste Building and Reactor Auxiliary Bay components:

- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.16 Reactor Building

Materials

The materials of construction for the Reactor Building components are:

- Aluminum
- Aluminum Bolting
- Boralcan (Rio Tinto Alcan Composite)
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Building components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Groundwater/Soil
- Treated Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Reactor Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload
- Reduction of Neutron Absorbing Capacity; Change in Dimensions and Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building components:

- Masonry Walls (B.2.1.33)
- Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.27)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)
- Water Chemistry (B.2.1.2)

3.5.2.1.17 Recombiner Building

Materials

The materials of construction for the Recombiner Building components are:

- Aluminum
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete
- Stainless Steel Bolting

Environments

The Recombiner Building components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Recombiner Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Recombiner Building components:

- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.18 Stack

Materials

The materials of construction for the Stack components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Reinforced concrete
- Stainless Steel Bolting

Environments

The Stack components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Stack components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Stack components:

- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.19 Station Blackout Structure and Foundations

Materials

The materials of construction for the Station Blackout Structure and Foundations components are:

- Aluminum
- Aluminum Bolting
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Ductile Iron
- Galvanized Steel
- Reinforced concrete

- Stainless Steel

Environments

The Station Blackout Structure and Foundations components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Station Blackout Structure and Foundations components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Material; Loss of Form
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Station Blackout Structure and Foundations components:

- FERC Inspections of the Conowingo Hydroelectric Plant (Dam)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.20 Turbine Building and Main Control Room Complex

Materials

The materials of construction for the Turbine Building and Main Control Room Complex components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting

- Concrete
- Concrete Block
- Galvanized Steel
- Lubrite
- Reinforced concrete
- Stainless Steel Bolting

Environments

The Turbine Building and Main Control Room Complex components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Turbine Building and Main Control Room Complex components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Mechanical Function
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building and Main Control Room Complex components:

- Masonry Walls (B.2.1.33)
- One-Time Inspection (B.2.1.21)
- Structures Monitoring (B.2.1.34)

3.5.2.1.21 Watertight Dikes

Materials

The materials of construction for the Watertight Dikes components are:

- Reinforced concrete

Environments

The Watertight Dikes components are exposed to the following environments:

- Air - Outdoor
- Groundwater/Soil

Aging Effects Requiring Management

The following aging effects associated with the Watertight Dikes components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Loss of Material (Spalling, Scaling) and Cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Watertight Dikes components:

- Structures Monitoring (B.2.1.34)

3.5.2.1.22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.)

Materials

The materials of construction for the Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Steel
- Galvanized Steel Bolting
- Reinforced concrete

Environments

The Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) components:

- Structures Monitoring (B.2.1.34)

3.5.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Containments, Structures and Component Supports, those programs are addressed in the following subsections.

3.5.2.2.1 Pressurized Water Reactor and Boiling Water Reactor Containments

3.5.2.2.1.1 Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's current licensing basis (CLB) credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

Table 3.5.1 Item Number 3.5.1-001: This item is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS so the ASME Code Section XI, Subsection IWL is not applicable at PBAPS.

Table 3.5.1 Item Number 3.5.1-002: This item is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1.

The containment is supported on the reactor building foundation. The reactor building foundation design does not incorporate porous concrete in the sub-foundation. Dewatering was used during original construction, as described in UFSAR Section 2.8.5, but the plant's current licensing basis (CLB) does not credit a dewatering system to control settlement. The Structures Monitoring (B.2.1.34) program, will be used to manage cracks and distortion due to increased stress level from settlement for the reactor buildings. However, this aging mechanism is insignificant for the PBAPS reactor building structures because the structures are founded on bedrock as described in UFSAR Section 2.7.6.3. Cracking and distortion due to settlement has not been identified in PBAPS power block concrete structures. The condition of accessible and above grade reactor building 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. Cracks extending into accessible areas, if any, will be managed by the Structures Monitoring (B.2.1.34) program. In the event that unacceptable conditions due to this mechanism were identified in the accessible areas of structures, procedures require that extent of condition be determined and additional inspections or evaluations would address inaccessible and below grade portions of the structure. Also, reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete sub-foundation is not applicable because porous concrete is not used in the foundation design. The Structures Monitoring (B.2.1.34) program is described in Appendix B.

3.5.2.2.1.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended of a plant-specific AMP if any portion of the concrete containment components exceeds specified temperature limits {i.e., general area temperature greater than 66 °C (Celsius) [150 °F (Fahrenheit)] and local area temperature greater than 93 °C (200 °F)}. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-LR).

Table 3.5.1 Item Number 3.5.1-003: This item is not applicable to the PBAPS steel containment. The components for this Item Number are concrete containment components. The Technical Specifications limit the bulk air temperature inside the drywell during normal plant operation to 145 degrees Fahrenheit. The bulk air temperature is maintained within the Technical Specification limits by recirculating air through the Drywell Ventilation System. The normal drywell environment is described in UFSAR Sections 5.2.3.2 and 5.2.3.7 as a bulk average temperature of 145 degrees Fahrenheit or lower. Therefore, concrete structural components located inside the drywell are not subject to general area temperature greater than 150°F or local area concrete temperature greater 200°F. Plant operating experience has not identified elevated general area and local area temperature as a concern for concrete structural components.

The potential for gamma radiation induced heating in the sacrificial shield wall is addressed in EPRI report 3002002676, revision 0, February 2014, “Expected Condition of Reactor Cavity Concrete After 80 Years of Radiation Exposure”, which concludes that the gamma dose for BWR plants will be no higher than the gamma dose for PWR plants. EPRI report 3002008129, revision 0, December 2016, “Long-Term Operations: Impact of Radiation Heating on PWR Biological Shield Concrete” evaluates the impact of radiation induced heating on bounding PWR plants. The evaluation determined that the localized temperature rise in the shield wall resulted in a localized concrete temperature of less than 180°F. Therefore, this report also indicates that the localized temperatures in the PBAPS sacrificial shield wall are less than 200°F. The configuration of the PBAPS sacrificial shield wall, which is described in UFSAR Section C.4.6, reflects the configuration shown in EPRI report 3002002676, Figure 7.6, for the wall described as a biological shield in the figure.

3.5.2.2.1.3 Loss of Material Due to General, Pitting and Crevice Corrosion

1. *Loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J AMPs, to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Table 3.5.1 Item Numbers 3.5.1-004 and 3.5.1-005 are not applicable to the PBAPS Mark I steel containments. This Item is applicable instead to Mark II and Mark III containments. However, Item Number 3.5.1-035 is applicable to PBAPS. The ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program will be used to manage the loss of material of steel elements in the accessible and inaccessible areas of the integral attachments, penetration sleeves, drywell shell, drywell head, drywell shell in the sand pocket regions, and embedded shell exposed to air-indoor. The majority of the PBAPS IWE surfaces, including the drywell head, are accessible for inspection. Preventive actions associated with Mark I steel containments as addressed by LR-ISG-2006-01 including those associated with sand pockets and sand pocket area drains are applicable to the Peach Bottom Mark I metallic containments.

The PBAPS primary containment design includes an accessible moisture barrier at the bottom floor inside of the drywell and includes an inaccessible sheet metal cover and joint sealing compound above the sand pocket region on the exterior of the drywell shell. The ASME Section XI, Subsection IWE (B.2.1.30) program performs an examination of the accessible moisture barriers at the interior concrete to shell interface for wear, damage, erosion, tears, cracks, or other defects that may violate the leak-tight integrity. The examination of moisture barriers intended to prevent intrusion of moisture into inaccessible areas of the pressure retaining metal containment shell. There has been no corrosion detected at the moisture barrier at the bottom of the drywell interior. Additionally, there has been no reported evidence of moisture or degradation when the stabilizer access hatch covers at the top of the drywell cylinder are opened to perform examinations of the shear lugs attached to the exterior of the drywell shell. Any signs of degradation of the moisture barrier are entered into the corrective action program, evaluated and promptly repaired.

The PBAPS air gap design incorporates seal rupture drains to divert drywell bellows leakage. The PBAPS design incorporates a weir wall that prevents drywell bellows leakage from entering the drywell air gap before being drained away by drains to radwaste. The PBAPS design also prevents in-leakage to the sand pocket by use of a sheet metal cover which is sealed to the drywell shell. This sealed cover separates the sand pocket from the air gap region. Located at the level of the sealed cover plate are air gap drains that remove any inleakage away from the sealed cover plate. The design was addressed in the license amendment change for the extension of type A and type C leak rate test frequencies (reference NRC ML15196A559).

As part of the ASME Section XI, Subsection IWE (B.2.1.30) program, several examinations and tests of components associated with the drywell air gap region confirm that abnormal conditions which could lead to containment degradation would be identified and conditions addressed before loss of an intended function.

The following examinations are performed on the four drywell air gap drain lines:

1. A functional test (i.e. smoke test) is performed on the four drywell air gap drains once every 10 year interval to verify that the drywell air gap drain lines are unclogged and functional.

2. A visual examination is performed on the drywell air gap drain lines once each period when the refueling cavity is flooded to look for signs of leakage.

The above described examinations and tests have been routinely performed with acceptable results for both units detecting no evidence of leakage through the drains or flow blockage of the drains.

Furthermore, when stabilizer access hatches towards the top of the drywell cylinder are opened to perform the examinations of the shear lugs attached to the exterior of the drywell shell, a VT-3 visual examination is performed on the following items:

1. The drywell exterior stabilizer support.

2. The accessible exterior surface of the drywell to look for evidence of degradation or leakage.

3. The accessible drywell air gap to look for items that could trap water in the unlikely event of leakage through the refueling bellows.

Inspection results of these examinations have confirmed that no evidence of moisture or degradation exists.

This robust design, along with the monitoring and testing measures described, provide substantial defense against water entering the drywell air gap region. With no water intrusion, potential degradation on the outside surface of the drywell is prevented. The station approach to ensure no evidence of moisture or degradation on the inaccessible surfaces of the metal shell was submitted to the NRC in the PBAPS Generic Letter 87-05 response, dated May 11, 1987 and also for the LAR – Revise TS 5.5.12 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies, dated November 7, 2014, approved by the NRC via Amendment No. 302 to Renewed DPR-44 and Amendment No. 306 to Renewed DPR-56, dated September 8, 2015.

For PBAPS, no additional plant-specific activities are warranted beyond those described above and those that are currently established as part of the ASME Section XI, Subsection IWE (B.2.1.30) program. The continued monitoring of the containment shell in accordance with the ASME Section XI, Subsection IWE (B.2.1.30) program, and the testing conducted in accordance with the 10 CFR Part 50, Appendix J (B.2.1.32) program provide reasonable assurance that the loss of material due to corrosion of steel elements of the containment will be detected prior to a loss of intended function. These activities and programs provide assurance that the containment liner will remain capable of performing its design function through the period of extended operation.

The ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program are described in Appendix B.

2. *Loss of material due to general, pitting, and crevice corrosion could occur in steel torus shell of Mark I containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. If corrosion is significant, recoating of the torus is recommended. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   Table 3.5.1 Item Number 3.5.1-006: This item evaluates loss of material due to general, pitting, and crevice corrosion in steel torus shell of the PBAPS Mark I containment exposed to air-indoor and treated water environments. The ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program will be used to manage the loss of material of steel elements in the torus shell. These wetted surface areas are required to be 100 percent visually examined in the current ISI Interval.

   In 2012 (Unit 2) and 2013 (Unit 3), as a result of previous monitoring and trending of coating condition, the torus was drained, and the torus interior up to nominally 1 foot above the normal waterline was cleaned, prepared, and the coating was replaced with a qualified Service Level I coating, replacing the original coating. At Unit 2, due to the presence of a nominally two-foot wide epoxy band centered along the normal waterline that was previously applied on the interior of the torus shell and left in place, the coating applied in 2012 on the torus shell goes up to nominally one foot below the normal waterline.

   Periodic inspections continue to be performed on the wetted surfaces in accordance with the ASME Section XI, Subsection IWE (B.2.1.30) program.

   During the following Unit 2 outage in 2014, a follow-up underwater coating inspection was performed to confirm the adequacy of the replacement coating. The inspection in 2014 found the coatings to be in good condition with limited holidays and other spot corrosion issues. These deficiencies had been identified in the corrective action program in 2012, evaluated, and corrected as necessary during the same outage. As an example, the diver examination identified a local area (1/8 inch diameter) of general corrosion with 0.126 inches of metal loss of the nominal 0.675 inch thick plate on the inside of the torus with no losses identified on the outside of the torus. The condition was entered into the corrective action program and was evaluated prior to the unit startup from the refueling and maintenance outage. An engineering evaluation was performed and confirmed acceptability of the torus shell pressure boundary with the as-found local general corrosion without repair. The associated coatings were repaired prior to startup. Follow-up inspections will be performed under the ASME Section XI, Subsection IWE (B.2.1.30) program in accordance with ASME Table IWE-2500-1, Examination Category E-C.

   During the following Unit 3 outage in 2015, a follow-up underwater coating inspection was performed to confirm the adequacy of the replacement coating. The inspection in

2015 found the coatings to be in good condition with limited holidays and other spot corrosion issues. These deficiencies had been identified in the corrective action program in 2013, evaluated, and corrected as necessary during the same outage.

Examinations conducted in accordance with ASME Section XI, Subsection IWE have not identified significant corrosion in the steel torus shell of the PBAPS Mark I containment.

The ASME Section XI, Subsection IWE (B.2.1.30) program is described in Appendix B.

3. *Loss material due to general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments. The existing program relies on ASME Code Section XI, Subsection IWE to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

   Table 3.5.1 Item Number 3.5.1-007: This item evaluates loss of material due to general, pitting, and crevice corrosion in steel torus ring girders and downcomers of the PBAPS Mark I containment exposed to air-indoor and treated water environments. The ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage the loss of material of steel torus ring girders and downcomers.

   Steel torus ring girders and downcomers of the PBAPS 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 PBAPS operating experience associated with the torus ring girders and downcomers that has identified loss of material due to pitting and crevice corrosion as a result to exposure to air-indoor and treated water. Examinations have identified very small weld imperfections of stiffener welds to the ring girders and general corrosion of the downcomers. These conditions have been documented in the corrective action program, evaluated, and the conditions corrected as required. Any future deficiencies will be documented and addressed in accordance with corrective action program.

   The implementation, of the ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program, provide reasonable assurance that loss of material due to corrosion of the steel torus ring girders and downcomers will be adequately managed during the period of extended operation such that the intended functions of Mark I containment are maintained consistent with the current licensing basis.

   The ASME Section XI, Subsection IWE (B.2.1.30) program and 10 CFR Part 50, Appendix J (B.2.1.32) program are described in Appendix B.

3.5.2.2.1.4 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete *containments is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.5, "Concrete Containment Unbonded Tendon Pre-stress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.*

Table 3.5.1 Item Number 3.5.1-008: This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to PWR and BWR prestressed concrete containments.

3.5.2.2.1.5 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of metal liner, metal plates, suppression pool steel shells (including welded joints) and penetrations (including personnel airlock, equipment hatch, control rod drive (CRD) hatch, penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers may be TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in Section 4.6, "Containment Liner Plates, Metal Containments, and Penetrations Fatigue Analysis," and for cases of plant-specific components, in Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

Table 3.5.1 Item Number 3.5.1-009: This item evaluates cumulative fatigue damage due to cyclic loading (only for an existing analysis that is part of the CLB) in 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), vent header, vent line bellows, and downcomers of the PBAPS Mark I containment exposed to air-indoor and treated water environments. Components of the primary containment that were analyzed for fatigue and evaluated as a TLAA include the PBAPS torus, torus penetrations, vent header and downcomers, drywell to torus vents, safety relief valve discharge piping externally attached to the torus, other piping attached to the torus, drywell to torus vent bellows, and RHR and Core Spray suction strainers. These components are addressed in Section 4.6.1. In addition, the evaluation of fatigue as a TLAA, for the containment process line penetration bellows, is addressed in Section 4.6.2 and the evaluation of fatigue as a TLAA, for the Unit 3 RHR supply and return line penetrations, is addressed in Section 4.3.2.

The PBAPS Unit 2 and Unit 3 drywell structures, penetrations, and associated components were determined not to have an existing fatigue analysis and therefore have no fatigue TLAAs. These drywell components include the drywell shell, drywell head, drywell personnel airlock, drywell equipment hatches, drywell CRD removal hatch, drywell electrical penetrations, and drywell mechanical penetrations except for bellows and the Unit 3 RHR supply and return line penetrations. The containment analysis was completed in accordance with the original design specifications. Fatigue analysis, or a fatigue waiver, for the drywell shell, drywell head, or drywell penetrations was not required since no cyclical loads were identified for these components in the applicable design specifications per the CLB.

Subsequent to the original design, design changes were made to some portions of the containment, which added new requirements for fatigue analyses, which are considered TLAAs, as described below.

During the 1980's, elements of the PBAPS Units 2 and 3 primary containments were reanalyzed in response to discoveries, by General Electric and others, of unevaluated loads due to design basis events and safety relief valve (SRV) discharge. The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge and design basis loss of coolant accident (LOCA) events. Components of the primary containment that were analyzed included the torus shell, torus penetrations, the drywell-to-torus vent piping, SRV discharge piping, other piping attached to the torus, and the drywell to torus vent bellows. As such, these components were analyzed for fatigue and are considered TLAAs, which are addressed in Section 4.6.1.

In the 1980s the PBAPS replaced reactor recirculation and the residual heat removal (RHR) system piping on both units. The Unit 3, the drywell flued-head penetrations for the RHR system were also replaced and analyzed for fatigue in accordance with ASME Section III, Class 1 requirements. These components were analyzed for fatigue and these analyses are considered TLAAs, which are addressed in Section 4.3.2.

In 1997 and 1998 PBAPS Units 2 and 3 replaced the RHR and Core Spray System suction strainers. These new strainers and their supports were designed to ASME Section III, Subsections NC, NE, and NF, 1980 edition up to and including Winter 1981 Addenda. As such, the new strainers and supports were analyzed for fatigue, and these analyses are considered TLAAs, which are addressed in Section 4.6.1.

3.5.2.2.1.6 Cracking Due to Stress Corrosion Cracking

Stress corrosion cracking (SCC) of stainless steel (SS) penetration sleeves, penetration bellows, vent line bellows, suppression chamber shell (interior surface), and dissimilar metal welds could occur in PWR and/or BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE and10 CFR Part 50, Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable operating experience (OE) related to detection, is recommended of additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds.

Table 3.5.1 Item Number 3.5.1-010 and Item Number 3.5.1-039: These items evaluate cracking due to SCC in stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds of the PBAPS Mark I containment exposed to an air-indoor environment. The enhanced ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program will be used to manage the cracking of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds. The suppression chamber shell at PBAPS is made of carbon steel and is not susceptible to SCC.

Cracking due to SCC in stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds is not expected to occur at PBAPS because stress corrosion cracking requires a concentration of chloride or sulfate contaminants, which are not present in significant quantities inside the containment or in plant systems, as well as high stress levels, and high temperatures. The containment components are located in an air-indoor environment and are not subject to conditions that promote corrosion or SCC.

Cyclical loading of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds is not expected to result in SCC at PBAPS because of the containment design which limits cyclical loadings to acceptable levels. The design of penetrations, which exhibit significant differences in temperature during plant operations, limit loads from the piping onto the drywell by either using bellows or installation of small bore diameter pipe. The containment analysis was completed in accordance with the original design specifications. Fatigue analysis, or a fatigue waiver, for the drywell penetrations was not required since no cyclical loads were identified for these components in the applicable design specifications per the CLB. However, PBAPS Units 2 and 3 process lines that penetrate the drywell and experience significant differences in temperature during plant operation were designed with penetration bellows to ensure that fatigue due to thermal loads during plant operation is acceptable, preventing one potential cause of SCC at the penetrations. The following process lines were designed with penetration bellows: the main steam lines, the feedwater lines, the HPCI steam line, the RHR supply and return lines, the RWCU pump suction line, the core spray discharge lines, and the vessel head spray line. In addition, during the preparation of this application, PBAPS has performed an assessment to show that the drywell would have met the criteria for a fatigue waiver. License renewal applications for other similar Mark I containments designed to later code years have credited fatigue waivers. The criteria that were met for the fatigue waiver included: 1) atmospheric to operating pressure cycles, 2) normal operation pressure fluctuations, 3) temperature differences between startup and shutdown, 4) temperature differences during normal operation, 5) temperature differences at dissimilar metals, and 6) mechanical loads. The drywell fatigue waiver assessment concluded that the components that could be subject to cyclic loading but have no current licensing basis fatigue analysis are subjected to an acceptable and negligible amount of fatigue. The fatigue waiver assessment did not include drywell high temperature mechanical penetrations, listed above, which have bellows or are limited to small pipe diameters. The containment components with a fatigue analysis that are addressed in Section 3.5.2.2.1.5 and Sections 4.3.2 and 4.6 are representative of the stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds and can be used as a leading indicator for these components.

Plant operating experience confirms that SCC of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds of the PBAPS Mark I containment is not expected. Original design and installation specifications for containment penetration components such as bellows, welds, and penetration adapters required initial surface examinations to ensure no flaws existed as part of initial installation. Appropriate integrated and local leak rate testing is conducted for pressure boundary components per the 10 CFR Part 50, Appendix J (B.2.1.32) program. Through-wall cracking would be detected by the type A integrated leak rate test. Additionally, VT-3 examinations are performed on accessible portions of the containment penetrations in accordance with the ASME Section XI, Subsection IWE (B.2.1.30) program. Peach Bottom has not experienced a failure of the above listed containment components and integrated leak rate test results have shown significant margin. Industry operating experience has also shown strong performance of the primary containment components.

Even though the aging effect of SCC of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds is not expected to occur, the testing conducted in accordance with the 10 CFR Part 50, Appendix J (B.2.1.32) program and examinations conducted in accordance with the ASME Section XI, Subsection IWE (B.2.1.30) program are applied to manage this aging effect and provide reasonable assurance that the cracking of stainless steel containment penetration bellows and dissimilar metal welds at containment penetration sleeves will be detected prior to a loss of intended function.

In addition, to address concerns identified in this Further Evaluation, as well as Item Number 3.5.1-027, the ASME Section XI, Subsection IWE (B.2.1.30) program will be enhanced to perform surface examinations on accessible portions of drywell high temperature mechanical penetrations, in addition to visual examinations, to detect SCC at penetrations that could be subject to cyclic loading but have no CLB fatigue analysis. The majority of the surface of the stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds are not accessible for visual inspection or surface examination for cracking due to the Mark I containment design but the ends of these penetrations are accessible, and representative of other areas of these penetrations and the other stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds.

Therefore, the 10 CFR Part 50, Appendix J (B.2.1.32) program and enhanced ASME Code Section XI, Subsection IWE (B.2.1.30) program, in conjunction with the additional examinations described above, will detect SCC for these stainless steel components and dissimilar metal welds prior to a loss of intended function.

The ASME Section XI, Subsection IWE (B.2.1.30) program and the 10 CFR Part 50, Appendix J (B.2.1.32) program are described in Appendix B.

Table 3.5.1 Item Number 3.5.1-038: This item is not applicable to the PBAPS Mark I steel containment. This Item is applicable instead to Mark III containments.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended of this aging effect for plants located in moderate to severe weathering conditions.

Table 3.5.1 Item Number 3.5.1-011: This item is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure. The Containment Structure is completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). Containment Structure concrete is not exposed to air-outdoor, or groundwater/soil environments. Thus, repeated freeze-thaw is not applicable, and Containment Structure concrete is not subject to loss of material (scaling, spalling) and cracking due to freeze-thaw. Therefore, no additional aging management or further evaluation of inaccessible concrete of the Containment Structure for this mechanism is required.

3.5.2.2.1.8 Cracking Due to Expansion From Reaction With Aggregates

Cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The GALL-SLR Report recommends further evaluation to determine if a plant-specific aging management program is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-012: This item is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure. The Containment Structure is completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). Therefore, no additional aging management or further evaluation of inaccessible concrete of the Containment Structure for this mechanism is required.

3.5.2.2.1.9 Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-014: This item is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure. The Item Number is applicable only to PWR and BWR concrete containments. The Containment Structure is completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). The Containment Structure is also not subject to a flowing water environment, which would be conducive to porosity and permeability due to leaching of calcium hydroxide and carbonation. No increase in porosity and permeability has been identified in accessible areas of the Containment Structure that could have an impact on intended function. Therefore, no additional aging management or further evaluation of inaccessible concrete of the Containment Structure for this mechanism is required.

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 is recommended of this aging effect for inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions.*

   Table 3.5.1 Item Number 3.5.1-042: This aging effect and mechanism, the loss of material (spalling, scaling) and cracking due to freeze-thaw, is applicable to PBAPS reinforced concrete structures. PBAPS is located in a region where weathering conditions are considered severe as shown in ASTM C33. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of reinforced concrete for the Groups 2, 3, and 9 structures. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which at PBAPS, are part of the Group 2 Reactor Buildings. PBAPS does not have any Group 7 or 8 structures. None of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas.

   The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix design provides for low permeability, by incorporating fly ash and water reducing agents, and adequate air entrainment (3 percent to 6 percent) in the air-outdoor environment such that the concrete has good freeze-thaw resistance.

   Structural reinforced concrete has not exhibited significant loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of in scope reinforced concrete structures. This operating experience provides objective evidence that the design and construction of external reinforced concrete at PBAPS has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Structures Monitoring (B.2.1.34) program includes inspection for these aging effects in the accessible areas.

   In addition, PBAPS examines exposed portions of the below-grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling.

   The visual inspections of reinforced concrete identify concrete damage in accordance with the requirements of the Structures Monitoring (B.2.1.34) program. If unacceptable conditions due to freeze thaw are identified in the accessible areas of structures, the conditions are evaluated and depending upon the initial conditions and evaluation, corrective actions are developed that may include additional inspections to determine the extent of degraded conditions as part of the corrective action process.

If freeze thaw damage were to occur, it would occur at the surface of concrete with significant moisture levels and sudden drops in temperature to below freezing. In general, these areas are exposed at the ground surface and are accessible for inspection. Because of the higher level of water exposure, the accessible PBAPS Group 6 structures may be used as a leading indicator for exposure to weathering conditions for the other reinforced concrete structures that are in scope.

The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

The frost line per the original design criteria was three feet below the surface grade. Since the number of freeze-thaw cycles is expected to be greater for concrete above grade, and the potential moisture content in the concrete is expected to also be significant at the grade surface, inaccessible portions of the reinforced concrete structures are expected to be less susceptible to freeze-thaw damage than exposed areas of reinforced concrete structures.

Since freeze-thaw damage proceeds at a comparatively slow rate, the required five-year inspection frequency of the Structures Monitoring (B.2.1.34) program is adequate to address any significant concrete damage due to freeze-thaw before a loss of intended function. As a result, the Structures Monitoring (B.2.1.34) program is expected to adequately manage the loss of material (spalling, scaling) and cracking due to freeze-thaw that could occur in below grade inaccessible areas of reinforced concrete structures.

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas for Groups 1–5 and 7–9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures to determine if a plant-specific AMP is required to manage this aging effect.*

   Table 3.5.1 Item Number 3.5.1-043: This aging effect and mechanism, cracking due to expansion and reaction with aggregates, is considered applicable to PBAPS reinforced concrete structures. The Structures Monitoring (B.2.1.34) program will be used to manage cracking due to expansion and reaction with aggregates in both accessible and inaccessible areas of reinforced concrete for the Groups 2, 3, 4, and 9 structures. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which at PBAPS, are part of the Group 2 Reactor Buildings. PBAPS does not have any Group 7 or 8 structures. None of these structures are completely inaccessible, and there are significant portions of the structures that are accessible. The accessible portions of the structures provide indications of reinforced concrete conditions in inaccessible areas.

   The PBAPS structural concrete was constructed as recommended to preclude cracking due to this mechanism. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR

Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix specification requirements minimized the potential for expansion and reaction with aggregates. The concrete mix designs provide for low permeability, by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. Petrographic examinations of aggregates used in concrete were performed in accordance with ASTM C295, "Petrographic Examination of Aggregates for Concrete", and ASTM C289, "Potential Reactivity of Aggregates", to demonstrate that the aggregates do not adversely react within the concrete. The cement is Type II, Portland cement conforming to ASTM C-150, with alkali content limited to 0.6 percent by weight.

Cracking associated with expansion due to reaction with aggregates has not been observed on PBAPS Group 2, 3, 4, and 9 concrete structures. Nevertheless, the Structures Monitoring (B.2.1.34) program continues to inspect and monitor reinforced concrete structures for cracking due to any mechanism. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected over most of the surfaces at grade level where the moisture level is higher. This has not occurred. The Group 6 structures, Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir, which have higher exposure to water compared to other reinforced concrete structures at PBAPS, may be used as leading structures to indicate the presence of expansion and reaction with aggregates for the other reinforced concrete structures that are in scope, as described in Subsection 3.5.2.2.2.3.2

In addition, significant concrete deformations due to concrete expansion has not been detected at the PBAPS. No significant concrete deformations due to differences in concrete expansion have been detected at the various accessible concrete structures that can be identified by looking for cracking between concrete elements below and above grade or at visible seismic gaps or expansion joints. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of PBAPS, the possibility of occurrence becomes unlikely. Nevertheless, PBAPS will continue to look for indications of cracking associated with expansion due to reaction with aggregates.

PBAPS also examines exposed portions of the below grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling. This operating experience also provides objective evidence that the concrete at PBAPS is not susceptible to cracking associated with expansion due to reaction with aggregates.

Since cracking due to expansion and reaction with aggregates at a comparatively slow rate, the required five-year inspection frequency, of the Structures Monitoring (B.2.1.34) program, 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 (B.2.1.34) program is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of Group 2, 3, 4, and 9 structures. Therefore, a plant-specific AMP is not required to manage this aging effect.

3. *Cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all Groups, and reduction in foundation strength, and cracking due to differential settlement and erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5–9 structures. The existing program relies on structure monitoring programs to manage these aging effects. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, verification is recommended of the continued functionality of the dewatering system during the subsequent period of extended operation. No further evaluation is recommended if this activity is included in the scope of the applicant's structures monitoring program.*

   Table 3.5.1 Item Number 3.5.1-044: The Structures Monitoring (B.2.1.34) program, will be used to manage cracks and distortion due to increased stress level from settlement for the Groups 1, 2, 3, 8, and 9 structures. At PBAPS, the there are no stand-alone Group 5 structures, which at PBAPS, are part of the Reactor Buildings. PBAPS does not have any Group 7 structures. However, this aging mechanism is insignificant for the PBAPS concrete building structures founded on bedrock as described in UFSAR Section 2.7.6. Cracking and distortion due to settlement has not been identified in PBAPS concrete building structures. Nevertheless, the Structures Monitoring (B.2.1.34) program continues to inspect and monitor concrete structures for cracking due to any mechanism.

   The foundations for the Diesel Generator Building and the Administration Building and Shop consist of steel piles that are founded on bedrock. At these structures, the steel piles support the basemats. Studies, such as those referenced in NUREG-1557, have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the deficient oxygen environment that prevents significant loss of material. Piles driven into disturbed soil, have been shown to experience only minor to moderate corrosion. In either case the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. The condition of the accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

   The 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. Cracks extending into accessible areas, if any, will be managed by the Structures Monitoring (B.2.1.34) program. If unacceptable conditions due to this mechanism were identified in the accessible areas of structures, procedures require that extent of condition be determined and additional inspections or evaluations would address inaccessible and below grade portions of any affected structure. In addition, PBAPS examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.34) program.

Table 3.5.1 Item Number 3.5.1-046: This item is not applicable. The foundation designs do not incorporate porous concrete in the sub-foundation as described in UFSAR Section 2.7.5. Dewatering was used during original construction, as described in UFSAR Section 2.8.5, but the plant's current licensing basis (CLB) does not credit a dewatering system to control building settlement. Since the magnitude of the total settlements is small, as described in UFSAR Section 2.7.6.3, the differential settlements are expected to be smaller, thus differential settlement distortion is insignificant for PBAPS structures.

4. *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions.*

Table 3.5.1 Item Number 3.5.1-047: This aging effect and mechanism, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation, is considered applicable to PBAPS reinforced concrete structures. The Structures Monitoring (B.2.1.34) program will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas for the Groups 2, 3, and 9 structures. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which at PBAPS, are part of the Group 2 Reactor Buildings. PBAPS does not have any Group 7 or 8 structures. This Item Number does not apply to the Group 4 structures due to the Mark I containment design. None of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas.

The same concrete specification was used for all structures at PBAPS, including the Groups 2, 3, 8, and 9 structures, such that these results are representative of the expected effects of leaching and carbonation of all structures within the scope of license renewal. The PBAPS structural concrete was constructed as recommended to minimize these potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix designs provide for low permeability, by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. Petrographic examinations of aggregates used in concrete were performed in accordance with ASTM C295, "Petrographic Examination of Aggregates for Concrete". The Cement is Type II, Portland cement conforming to ASTM C-150.

As described in NUREG/CR-5466, Service Life of Concrete, section 5.2.3.3, the rate and extent of carbonation depends on the environmental relative humidity, reaching a maximum at 50 percent relative humidity. Diffusion of gaseous carbon dioxide takes place several orders of magnitude more rapidly though air than through water. If the pores of concrete are saturated with water, the amount of carbonation occurring will be negligible. As a result, carbonation is more of a concern in accessible air environments, than in inaccessible soil or raw water environments. In addition, the carbonation rate of penetration slows over time. Therefore, accessible areas can be used as an indicator of reinforced concrete conditions in inaccessible areas for carbonation. The effects of carbonation have not been observed at PBAPS reinforced concrete structures. The same concrete specification was used for all structures at PBAPS, such that these results are representative of the expected effects of carbonation of all structures within the scope of license renewal. Therefore, the effects of carbonation, an increase in porosity and permeability, are not expected to occur at the Groups 2, 3, and 9 structures of PBAPS.

Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide is applicable for a flowing water environment; therefore, the potential for leaching to occur due to the water flowing environment is considered. Groundwater considered aggressive due to low pH or high sulfates could potentially result in chemical attack or leaching of the concrete. Concrete degradation due to chemical attack or leaching has not been observed at PBAPS.

Inaccessible below-grade reinforced concrete for Groups 2, 3, and 9 structures is subject to an aggressive environment. Test results for groundwater and raw water samples taken between 2016 and 2018 showed pH limits are safely above the threshold limit for pH > 5.5, and sulfates are safely lower than the threshold limit for sulfates <1500 ppm and this would indicate a non- aggressive environment. Chlorides in a minority of groundwater testing wells exceed the threshold limit for chlorides < 500 ppm, which indicates an aggressive environment. All of the raw water tests, e.g., river water, were safely less than the threshold limit for chlorides < 500 ppm which indicates a non-aggressive environment. Therefore, only the ground water is considered to be aggressive and only for high chloride levels. High chloride levels are a concern as a potential initiator of reinforcing steel corrosion that could be initially detected as cracking and spalling of concrete. The groundwater at PBAPS is not aggressive with respect to pH or sulfates. Therefore, increase in porosity and permeability and loss of strength due to leaching is not expected.

Operating experience at PBAPS, which looks for concrete deterioration due to any mechanism, has not identified porosity and permeability and loss of strength due to these mechanisms. PBAPS also examines exposed portions of the below grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling. This operating experience also provides objective evidence that the concrete at PBAPS is not susceptible to an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide. This operating experience also provides objective evidence that the inaccessible below grade reinforced concrete at PBAPS is not exhibiting reinforcing steel corrosion, which might have been expected considering the high chloride levels found in a minority of some groundwater monitoring wells, as explained below.

The excessive chloride levels are not found consistently across the site and only found in a minority of the wells used for groundwater testing. In addition, these chloride levels are higher in the winter when the roads are salted and lower when the roads are not being salted. Other testing of soil for the aging management of buried pipe reveals chloride levels that are considered non-aggressive. Even though different testing methods and criteria are used for testing soils and water for chlorides, and considering that the diffusion rate of chlorides in water is higher than for soils, the soil tests provide evidence that there are not excessive chloride levels in the soil across the site and indicate that the chlorides in the road salt are being flushed away from the site instead of being absorbed in site structures. As a result, it is expected that high chloride levels will continue to exist in only localized areas across the site and only during short periods of time, after which the salts are flushed away by surface water. Since the solubility of chlorides in concrete is less than the solubility in soil or water, and since any salts will preferentially travel with water than diffuse into the concrete, it is concluded that the high chloride levels found in a few groundwater monitoring wells are expected to significantly exceed the chloride levels that would be found in concrete, which is not continuously exposed to groundwater with chloride levels considered to be aggressive with respect to reinforced concrete.

The Structures Monitoring (B.2.1.34) program will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Groups 2, 3, and 9 structures. In addition, PBAPS will continue will examine exposed portions of the below-grade concrete, when excavated for any reason. Therefore, no additional measures for managing the aging effect of increase in porosity and permeability, and loss of strength for concrete are required for inaccessible areas of Groups 1, 2, 3, 8, and 9 structures.

3.5.2.2.2.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Group 1–5 concrete structures. For any concrete elements that exceed specified temperature limits, further evaluations are recommended. Appendix A of American Concrete Institute (ACI) 349-85 specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 66 °C (150 °F) except for local areas, which are allowed to have increased temperatures not to exceed 93 °C (200°F). Further evaluation is recommended of a plant-specific program if any portion of the safety-related and other concrete structures exceeds specified temperature limits [i.e., general area temperature greater than 66 °C (150°F) and local area temperature greater than 93 °C (200 °F)]. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-048: This item is not applicable to PBAPS. A review of the Equipment Qualification specification for electrical equipment revealed that general area, normal temperatures greater than 150 degrees Fahrenheit and local temperatures in excess of 200 degrees Fahrenheit are not applied at PBAPS. Plant operating experience has not identified elevated general and local temperature as a concern for concrete structural components.

Group 5 structures, i.e., refuel floor and spent fuel storage pool are part of the Reactor Building which is a Group 2 structure. The spent fuel pool water bulk temperature is maintained at or below 150 degrees Fahrenheit under normal plant operating conditions, as described in UFSAR Section 10.5.3. The procedures for moving spent fuel restrict placement of fuel assemblies to ensure that there will be no significant gamma radiation induced heating of the concrete so that the maximum localized concrete temperature is estimated to be less than 180 degrees Fahrenheit.

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)/US Army Corp of Engineers dam inspection and maintenance procedures.

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.*

   Table 3.5.1 Item Number 3.5.1-049: This aging effect and mechanism, the loss of material (spalling, scaling) and cracking due to freeze-thaw, is applicable to PBAPS reinforced concrete structures. PBAPS is located in a region where weathering conditions are considered severe as shown in ASTM C33. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of Group 6 structures. The structures in the scope of this program consist of the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. Neither of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas. Because of the plant design, there are no dams, slopes, canals, and other raw water-control structures associated with emergency cooling water systems or flood protection in scope for second license renewal. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures.

   The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix design provides for low permeability, by incorporating fly ash and water reducing agents, and adequate air entrainment (3 percent to 6 percent) in the air-outdoor environment such that the concrete has good freeze-thaw resistance.

   Structural reinforced concrete has not exhibited significant loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of in scope reinforced concrete structures. This operating experience provides objective evidence that the design and construction of external reinforced concrete at PBAPS has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Structures Monitoring (B.2.1.34) program includes inspection for these aging effects in the accessible areas.

In addition, PBAPS examines exposed portions of the below-grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling.

The visual inspections of reinforced concrete identify concrete damage in accordance with the requirements of the Structures Monitoring (B.2.1.34) program. If unacceptable conditions due to freeze thaw are identified in the accessible areas of structures, the conditions are evaluated and depending upon the initial conditions and evaluation, corrective actions are developed that may include additional inspections to determine the extent of degraded conditions as part of the corrective action process.

If freeze thaw damage were to occur, it would occur at the surface of concrete with significant moisture levels and sudden drops in temperature to below freezing. In general, these areas are exposed at the ground surface and are accessible for inspection. Because of the higher level of water exposure, the accessible PBAPS Group 6 structures may be used as a leading indicator for exposure to weathering conditions for the other reinforced concrete structures that are in scope.

The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

The frost line per the original design criteria was three feet below the surface grade. Since the number of freeze-thaw cycles is expected to be greater for concrete above grade, and the potential moisture content in the concrete is expected to also be significant at the grade surface, inaccessible portions of the Group 6 structures are expected to be less susceptible to freeze-thaw damage than exposed areas of reinforced concrete structures.

Since freeze-thaw damage proceeds at a comparatively slow rate, the required five-year inspection frequency, of the Structures Monitoring (B.2.1.34) program, is adequate to address any significant concrete damage due to freeze-thaw before a loss of intended function. As a result, the Structures Monitoring (B.2.1.34) program is expected to adequately manage the loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures.

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine if a plant-specific AMP is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-050: This aging effect and mechanism, cracking due to expansion and reaction with aggregates, is considered applicable to PBAPS reinforced concrete structures. The Structures Monitoring (B.2.1.34) program will be used to manage cracking due to expansion and reaction with aggregates in both accessible and inaccessible areas of Group 6 structures. The structures in the scope of this program consist of the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. Neither of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas. Because of the plant design, there are no dams, slopes, canals, and other raw water-control structures associated with emergency cooling water systems or flood protection in scope for second license renewal. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures.

The PBAPS structural concrete was constructed as recommended to preclude cracking due to this mechanism. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix specification requirements minimized the potential for expansion and reaction with aggregates. The concrete mix designs provide for low permeability, by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. Petrographic examinations of aggregates used in concrete were performed in accordance with ASTM C295, “Petrographic Examination of Aggregates for Concrete”, and ASTM C289, “Potential Reactivity of Aggregates”, to demonstrate that the aggregates do not adversely react within the concrete. The Cement is Type II, Portland cement conforming to ASTM C-150, with alkali content limited to 0.6 percent by weight.

Cracking associated with expansion due to reaction with aggregates has not been observed on PBAPS Group 6 concrete structures, as described in the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program operating experience. Nevertheless, the Structures Monitoring (B.2.1.34) program continues to inspect and monitor Group 6 concrete structures for cracking due to any mechanism. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected over most of the surfaces of the Group 6 structures continuously exposed to water. This has not occurred.

In addition, significant concrete deformations due to concrete expansion has been not been detected at the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir, which have comparatively high exposure to water compared to other reinforced concrete structures at PBAPS. The Group 6 structures may be used as leading structures to indicate the presence of expansion and reaction with aggregates for the other reinforced concrete structures that are in scope. No significant concrete deformations due to differences in concrete expansion have been detected at the Circulating Water Pump Structure that can be identified by looking for cracking between concrete elements below and above water. In addition, inspections and operational checks of the sluice gates, mentioned in the operating experience for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program, have demonstrated that there has been no significant expansion of the submerged concrete that might have resulted in binding of the sluice gates. No significant concrete deformations due to concrete expansion have been detected at the Emergency Cooling Tower and Reservoir that can be identified by examining long conduit runs that extend around the corners of the concrete reservoir. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of PBAPS, the possibility of occurrence becomes unlikely. Nevertheless, PBAPS will continue to look for indications of cracking associated with expansion due to reaction with aggregates.

PBAPS also examines exposed portions of the below grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling. This operating experience also provides objective evidence that the concrete at PBAPS is not susceptible to cracking associated with expansion due to reaction with aggregates.

Since cracking due to expansion and reaction with aggregates at a comparatively slow rate, the required five-year inspection frequency, of the Structures Monitoring (B.2.1.34) program, 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 (B.2.1.34) program 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 structures. Therefore, a plant-specific AMP is not required to manage this aging effect.

3. *Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of Group 6 structures. Further evaluation is recommended if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-051: This aging effect and mechanism, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation, is considered applicable to PBAPS reinforced concrete structures. The Structures Monitoring (B.2.1.34) program will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 6 structures. The structures in the scope of this program consist of the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. Neither of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas. The Inspection of Water-Control Structures

Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures.

The same concrete specification was used for all structures at PBAPS, including the Group 6 structures, such that these results are representative of the expected effects of leaching and carbonation of all structures within the scope of license renewal. The PBAPS structural concrete was constructed as recommended to minimize these potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in UFSAR Appendix C) and ACI 301 (as referenced in UFSAR Appendix C and the construction specifications) except as noted. The concrete mix designs provide for low permeability, by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. Petrographic examinations of aggregates used in concrete were performed in accordance with ASTM C295, "Petrographic Examination of Aggregates for Concrete". The Cement is Type II, Portland cement conforming to ASTM C-150.

As described in NUREG/CR-5466, Service Life of Concrete, section 5.2.3.3, the rate and extent of carbonation depends on the environmental relative humidity, reaching a maximum at 50 percent relative humidity. Diffusion of gaseous carbon dioxide takes place several orders of magnitude more rapidly though air than through water. If the pores of concrete are saturated with water, the amount of carbonation occurring will be negligible. As a result, carbonation is more of a concern in accessible air environments, than in inaccessible soil or raw water environments. In addition, the carbonation rate of penetration slows over time. Therefore, accessible areas can be used as an indicator of reinforced concrete conditions in inaccessible areas for carbonation. The effects of carbonation have not been observed at PBAPS reinforced concrete structures. The same concrete specification was used for all structures at PBAPS, such that these results are representative of the expected effects of carbonation of all structures within the scope of license renewal. Therefore, the effects of carbonation, an increase in porosity and permeability, are not expected to occur at the Group 6 structures of PBAPS.

Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide is applicable for a flowing water environment; therefore, the potential for leaching to occur due to the water flowing environment is considered. Groundwater considered aggressive due to low pH or high sulfates could potentially result in chemical attack or leaching of the concrete. Concrete degradation due to chemical attack or leaching has not been observed at PBAPS.

Inaccessible below-grade reinforced concrete for Group 6 structures is subject to an aggressive environment. Test results for groundwater and raw water samples taken between 2016 and 2018 showed pH limits are safely above the threshold limit for pH > 5.5, and sulfates are safely lower than the threshold limit for sulfates <1500 ppm and this would indicate a non- aggressive environment. Chlorides in a minority of groundwater testing wells exceed the threshold limit for chlorides < 500 ppm which indicates an aggressive environment. All of the raw water tests, e.g., river water, were safely less than the threshold limit for chlorides < 500 ppm which indicates a non-aggressive environment. Therefore, only the ground water is considered to be aggressive and only for high chloride levels. High chloride levels are a concern as a potential initiator of reinforcing steel corrosion that could be initially detected as cracking and spalling of concrete. The groundwater at PBAPS is not aggressive with respect to pH or sulfates. Therefore, increase in porosity and permeability and loss of strength due to leaching is not expected.

Operating experience at PBAPS, which looks for concrete deterioration due to any mechanism, has not identified porosity and permeability and loss of strength due to these mechanisms. PBAPS also examines exposed portions of the below grade concrete, when excavated for any reason. As described in the Structures Monitoring (B.2.1.34) program operating experience, reinforced concrete was exposed during excavations and the exposed reinforced concrete looked sound, was not cracked, and did not exhibit any evidence of spalling. This operating experience also provides objective evidence that the concrete at PBAPS is not susceptible to an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide. This operating experience also provides objective evidence that the inaccessible below grade reinforced concrete at PBAPS is not exhibiting reinforcing steel corrosion, which might have been expected considering the high chloride levels found in a minority of some groundwater monitoring wells, as explained below.

The excessive chloride levels are not found consistently across the site and only found in a minority of the wells used for groundwater testing. In addition, these chloride levels are higher in the winter when the roads are salted and lower when the roads are not being salted. Other testing of soil for the aging management of buried pipe reveals chloride levels that are considered non-aggressive. Even though different testing methods and criteria are used for testing soils and water for chlorides, and considering that the diffusion rate of chlorides in water is higher than for soils, the soil tests provide evidence that there are not excessive chloride levels in the soil across the site and indicate that the chlorides in the road salt are being flushed away from the site instead of being absorbed in site structures. As a result, it is expected that high chloride levels will continue to exist in only localized areas across the site and only during short periods of time, after which the salts are flushed away by surface water. Since the solubility of chlorides in concrete is less than the solubility in soil or water, and since any salts will preferentially travel with water than diffuse into the concrete, it is concluded that the high chloride levels found in a few groundwater monitoring wells are expected to significantly exceed the chloride levels that would be found in concrete, which is not continuously exposed to groundwater with chloride levels considered to be aggressive with respect to reinforced concrete.

The Structures Monitoring (B.2.1.34) program will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 6 structures. In addition, PBAPS will continue will examine exposed portions of the below-grade concrete, when excavated for any reason. Therefore, no additional measures for managing the aging effect of increase in porosity and permeability; loss of strength for concrete are required for inaccessible areas of Group 6 structures.

3.5.2.2.2.4 Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP-SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant-specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant-specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One-Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50^{th} and 60^{th} year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.S6, "Structures Monitoring"); (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components;" or (c) developing a plant-specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been used, the SLRA states the specific alloy or temper used for the applicable in-scope components.

Table 3.5.1 Item Number 3.5.1-052: This item is not applicable to PBAPS. PBAPS does not have Group 7 and 8 stainless steel tank liners exposed to standing water.

Table 3.5.1 Item Number 3.5.1-099: For stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air environments, this Item Number evaluates the components aligned to this Item Number for loss of material due to pitting and crevice corrosion and cracking due to SCC. The One-Time Inspection (B.2.1.21) program will be used to manage cracking and loss of material of the stainless steel structural bolting and stainless steel elements for ASME Class 1, 2, and 3 supports exposed to air - indoor uncontrolled and air - outdoor in the Containment Structure and Component Supports commodity group. There were no aluminum components that were identified as applicable for this Item Number. A plant-specific OE review was performed using key words. The plant-specific OE does not reveal a history of pitting or crevice corrosion or cracking of aluminum or stainless steel support members or connections. The ASME Section XI, Subsection IWE (B.2.1.30) program and the ASME Section XI, Subsection IWF (B.2.1.31) program will continue to be used to examine the connections and supports aligned to this Item Number.

Cracking has not been identified as an aging effect at PBAPS for stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air environments, or as a result of exposure to secondary sources, indicating that the environments do not contain sufficient halides in the presence of moisture to result in SCC. Accordingly, visual inspections conducted in accordance with the One-Time Inspection (B.2.1.21) program will be performed to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC are not occurring at a rate that affects the intended function of the components. The one-time inspections will be conducted between the 50th and 60th year of operation. If loss of material or cracking is identified during the one-time inspections 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, the condition will be entered into the corrective action program. Depending upon the conditions found, corrective actions will include the actions such as the following: (a) enhancing the ASME Section XI, Subsection IWE (B.2.1.30) program and ASME Section XI, Subsection IWF (B.2.1.31) program; (b) determining the extent of condition by conducting a representative sample inspection consistent with the External Surfaces Monitoring of Mechanical Components (B.2.1.24) program; or (c) developing a plant-specific AMP to manage loss of material or cracking (as applicable).

Table 3.5.1 Item Number 3.5.1-100: For stainless steel and aluminum components or connections exposed to air environments, this Item Number evaluates the components aligned to this Item Number for loss of material due to pitting and crevice corrosion and cracking due to SCC. With the exception of aluminum alloy thermal insulation jacketing, specific aluminum alloys were typically not specified during original construction so the potential aging effects were considered for all aluminum components aligned to this Item Number. Aluminum alloy thermal insulation jacketing is constructed of alloy 1100, 3003, 3105, or 5005 with a magnesium content less than 3.5 weight percent. The aging effect of cracking is not applicable to aluminum insulation jacketing since these alloys are not susceptible to SCC.

A plant-specific OE review was performed using key words. The plant-specific OE does not reveal a history of pitting or crevice corrosion or cracking of aluminum or stainless steel components or connections. The One-Time Inspection (B.2.1.21) program will be used to manage loss of material for aluminum insulation jacketing as well as cracking and loss of material of stainless steel insulation and insulation jacketing exposed to air environments. The Structures Monitoring (B.2.1.34) program will continue to be used to examine the structural components and connections aligned to this Item Number. The

Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage cracking and loss of material of aluminum and stainless steel cranes, hoists, and their associated structural bolting exposed to air – indoor uncontrolled in the Fuel Handling System.

Cracking has not been identified as an aging effect at PBAPS for stainless steel and aluminum components or connections exposed to air environments, or as a result of exposure to secondary sources, indicating that the environments do not contain sufficient halides in the presence of moisture to result in SCC. Accordingly, visual inspections conducted in accordance with the One-Time Inspection (B.2.1.21) program will be performed to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC are not occurring at a rate that affects the intended function of the structural components. The one-time inspections will be conducted between the 50th and 60th year of operation. If loss of material or cracking is identified during the one-time inspections and is sufficient to potentially affect the intended function of the stainless steel components or connections, the condition will be entered into the corrective action program. Depending upon the conditions found, corrective actions will include the actions such as the following: (a) enhancing the Structures Monitoring (B.2.1.34) program and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program; (b) determining the extent of condition by conducting a representative sample inspection consistent with the External Surfaces Monitoring of Mechanical Components (B.2.1.24) program; or (c) developing a plant-specific AMP to manage loss of material or cracking (as applicable).

3.5.2.2.2.5 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports are TLAAs as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.3, "Metal Fatigue Analysis," and/or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

Table 3.5.1 Item Number 3.5.1-053: This Item Number is not applicable to PBAPS. The PBAPS current licensing basis contains no fatigue analysis for Groups B1.1, B1.2, and B1.3 component supports, which are screened under the Component Support group. A CLB fatigue analysis does not exist for support members, bolted connections, or supported anchorages to building structures are not subject to fatigue, cyclical loading, or cyclical displacement. Therefore, a TLAA is not required to be evaluated in accordance with 10 CFR 54.21(c) for these components.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and *gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light-water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1 × 10^{19} neutrons/cm^2 neutron radiation and 1 × 10^8 Gy (1 × 10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (Ref. 17, 18, 19).*

Further evaluation is recommended of a plant-specific program to manage aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation or if plant-specific OE of concrete irradiation degradation exists that may impact intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-097: The potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation of reinforced concrete due to irradiation primarily concerns the reactor vessel shield wall, also called the sacrificial shield wall, around the reactor vessel in the drywell. The sacrificial shield wall is described in UFSAR Section C.4.6. The reactor vessel is supported from the bottom on a skirt on the reactor vessel support/pedestal structure, as described in UFSAR Section C.4.4, where the radiation exposure is much less than at the sacrificial shield wall along the reactor vessel belt line. The reactor vessel support/pedestal structure is a reinforced concrete hollow cylinder supporting both the reactor vessel and the sacrificial shield wall. The bottom and top portions of the shield wall is comprised of standard density concrete with limestone coarse aggregate consisting of calcite and dolomite as well as quartz sand. The central portion of the sacrificial shield wall is comprised of high density, ilmenite concrete.

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 does not exceed the respective threshold level limits of 1 × 10^{19} neutrons/cm^2 neutron radiation or 1 × 10^{10} rad gamma dose during the subsequent period of extended operation. Therefore, a plant-specific program to manage aging effects of irradiation is not required and the Structures Monitoring (B.2.1.34) program will be used to manage the potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation of reinforced concrete due to irradiation near reactor vessel (sacrificial shield wall).

SLRA Table 4.2.2.1.1-1 shows a maximum fluence level of 2.23 × 10^{18} neutrons/cm^2 neutron radiation (fluence cutoff energy E > 1 MeV) at the inner diameter of the reactor vessel at the belt line for the 70 EFPY projected for the period of second period of extended operation. The maximum estimated fluence levels at the concrete are based upon determining the attenuation by the intervening reactor vessel shell and air gap and determining the neutron fluence levels at the energy levels of interest regarding potential concrete damage. The following is based upon EPRI report 3002008128, Revision 0, July 2016, "Structural Disposition of Neutron Radiation Exposure in BWR Vessel Support Pedestals".

- The following equation represents neutron attenuation through the thickness of the RPV:

  $f_{1T} = f_{0T}\ (e^{-0.33x})$ neutrons/cm^2 neutron radiation (fluence cutoff energy E > 1 MeV)

  Where:

  f_{1T} = neutron flux at the outside surface of the reactor vessel (1T) = 2.95×10^{17}
  f_{0T} = neutron flux at the inner surface of the reactor vessel (0T) = 2.23×10^{18}
  x = thickness of the reactor vessel = 6.125 inches

- The radiation exposure at the outside of the reactor vessel for neutrons with a fluence cutoff energy E > 0.1 MeV is estimated to be a factor of less than seven times the fluence values for neutrons with a fluence cutoff energy E > 1 MeV, which for PBAPS results in 2.95×10^{17} x 7 = 2.1×10^{18} neutrons/cm^2 neutron radiation (fluence cutoff energy E > 0.1 MeV).

- The neutron exposure at the concrete of the reactor vessel shield wall is attenuated by the air gap between the reactor vessel and the reactor vessel shield wall and is conservatively reduced by 10 percent. As a result, the neutron exposure at the inside surface of the concrete shield wall, conservatively ignoring the steel on the inside of the shield wall, is = 0.9 x 2.1×10^{18} = 1.9×10^{18} neutrons/cm^2 neutron radiation (fluence cutoff energy E > 0.1 MeV), which is less than the recommended radiation fluence limits of 1×10^{19} neutrons/cm^2 neutron radiation.

Two independent estimates of the gamma radiation levels were used to verify that recommended gamma radiation level would not be exceeded, which were based on an EPRI report that used a NUREG/CR-5449 estimate of radiation levels at a BWR shield wall as well as a PBAPS calculation of gamma radiation streaming through sacrificial shield wall penetrations.

The following is based upon EPRI report 3002002676, revision 0, February 2014, "Expected Condition of Reactor Cavity Concrete after 80 Years of Radiation Exposure". In section 3.5 of the EPRI report, the gamma radiation dose on the inside of the shield wall is estimated for three plants, one of which is a BWR. The estimated gamma dose at the BWR plant for 80 years is 4.27 x 10^9 rad. The dose at 80 years was extrapolated from NUREG/CR-5449, June 1990, "Determination of the Neutron and Gamma Flux Distribution in the Pressure and Cavity of a Boiling Water Reactor". EPRI report 3002002676 has a comparison of various neutron fluence levels that can be used to assess radiation levels at different plants. The PBAPS neutron fluence levels are less than one half the neutron fluence levels for the plant evaluated in NUREG/CR-5449, which indicates that the gamma dose levels at the inside of the sacrificial shield wall at Peach Bottom are estimated to be less than the limit of 1×10^{10} rad.

A plant specific calculation was used where the gamma radiation dose rate at the inside of the sacrificial shield wall of 1.53 x 10^4 Rem/hour was calculated for use in determining the potential radiation dose through sacrificial shield wall penetrations. Considering Rem equivalent to rad and extrapolating for 40 EFPY at 100 percent capacity for the originally licensed power levels and 40 years at 100 percent capacity for the uprated power levels, and then considering that there will be only 70 EFPY at the end of the second period of extended operation, reveals that the gamma dose will be 9.7 x 10^9 rad, which is less than the recommended limit of 1 x 10^{10} rad, and conservatively ignores the shielding effect from the one quarter inch thick carbon steel liner on the inside of the shield wall.

Recent research on the gamma dose limit of 1 x 10^{10} rad reveals that this value may be overly conservative after subsequent reviews of previous test data. A recent paper published by I. Maruyama et al, Journal of Advanced Concrete Technology, Volume 15, 440-523 (2017), funded by the Japanese Regulator, concluded that there is no direct effect of gamma dose on concrete strength and recommends removing gamma dose limits. This paper concludes that previous studies that showed a decrease in concrete strength as a function of gamma dose were seeing an elevated temperature effect due to the high gamma flux in accelerated aging tests. Similar issues with the gamma dose limit of 1 x 10^{10} rad were also identified in NUREG/CR-7171, November 2013, “A Review of the Effects of Radiation on Microstructure and Properties of Concrete Used in Nuclear Power Plants”.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3..

3.5.2.2.4 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, section B.1.4.

3.5.2.3 <u>Time-Limited Aging Analysis</u>

The time-limited aging analyses identified below are associated with the Structures and Component Supports:

Section 4.6, Primary Containment Fatigue Analyses

3.5.3 CONCLUSION

The Containments, 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 Containments, 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 second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Containments, Structures and Component Supports components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring"	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. See Subsection 3.5.2.2.1.1.
3.5.1-002	Concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. See Subsection 3.5.2.2.1.1.
3.5.1-003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill-in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program	Yes	Not Applicable. There are no containment concrete components exposed to elevated temperature (>150°F general; >200°F local) in the Containment Structures. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-004	Steel elements (inaccessible areas): drywell shell; drywell head	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to BWR Mark III containments. See Subsection 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	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to concrete containments and BWR Mark II containments. See Subsection 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 Programs	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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon steel elements in the torus shell exposed to air - indoor uncontrolled and treated water in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation. See Subsection 3.5.2.2.1.3.2.
3.5.1-007	Steel elements: torus ring girders; downcomers;, Steel elements: suppression chamber shell (interior surface)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE"	Yes	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon steel elements in the downcomers and torus shell and ring girders exposed to air - indoor uncontrolled and treated water in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation. See Subsection 3.5.2.2.1.3.3.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-008	Prestressing system: tendons	Loss of prestress due to relaxation; shrinkage; creep; elevated temperature	TLAA, SRP-SLR Section 4.5, "Concrete Containment Tendon Prestress," and/or SRP-SLR Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses"	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to PWR and BWR prestressed concrete containments. See Subsection 3.5.2.2.1.4.
3.5.1-009	Metal liner, metal plate, personnel airlock, equipment hatch, CRD hatch, penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.6, "Containment Liner Plate and Penetration Fatigue Analysis"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-010	Penetration sleeves; penetration bellows	Cracking due to SCC	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage cracking of the carbon steel, dissimilar metal welds, and stainless steel electrical and mechanical penetrations, mechanical penetration flued heads and bellows, and containment penetration sleeves exposed to an air - indoor uncontrolled environment in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation. See Subsection 3.5.2.2.1.6.
3.5.1-011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. See Subsection 3.5.2.2.1.7.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment, concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. See Subsection 3.5.2.2.1.8.
3.5.1-013	This Item Number is not listed in NUREG-2192.				
3.5.1-014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. See Subsection 3.5.2.2.1.9.
3.5.1-015	This Item Number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-016	Concrete (accessible areas): basemat, concrete: containment; wall	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure.
3.5.1-017	This Item Number is not listed in NUREG-2192.				
3.5.1-018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-019	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment; concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure.
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 PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure.
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 PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-022	This Item Number is not listed in NUREG-2192.				
3.5.1-023	Concrete (inaccessible areas): basemat; reinforcing steel, dome; wall	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring"	No	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure.
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 PBAPS Mark I steel containment, which is supported on steel supporting members, as shown in UFSAR Figure 5.2.1. The types of components described for this Item Number do not exist at PBAPS for the Containment Structure.
3.5.1-025	This Item Number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Consistent with NUREG-2191with exceptions. The ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of sealing of the elastomer seals, gaskets, and moisture barriers exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.
3.5.1-027	Metal liner, metal plate, airlock, equipment hatch, CRD hatch; penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage cracking of the carbon steel, carbon steel - dissimilar metal welds, and stainless steel penetrations, penetration flued heads and bellows, penetration sleeves, containment spares, access manholes, inspection ports, steel elements: vent line, header, and bellows exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon steel personnel airlock, CRD hatch, and equipment hatch exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.
3.5.1-029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of leak tightness of the carbon steel personnel airlock, CRD hatch, and equipment hatch locks, hinges, closure mechanisms exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-030	Pressure-retaining bolting	Loss of preload due to self-loosening	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of preload of the carbon and low alloy steel and stainless steel containment closure bolting exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.
3.5.1-031	Pressure-retaining bolting, steel elements: downcomer pipes	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon and low alloy steel containment closure bolting exposed to air-indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 PBAPS Mark I steel containment. The Item Number is applicable only to PWR and BWR prestressed concrete containments.
3.5.1-033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, "10 CFR Part 50, Appendix J "	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.1.32) program will be used to manage loss of sealing of the elastomer seals, gaskets, and moisture barriers exposed to air - indoor uncontrolled in the Containment Structure.
3.5.1-034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance (B.2.1.36) program will be used to manage loss of coating or lining integrity of the Service Level I coatings exposed to air - indoor uncontrolled in the Containment 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-035	Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, drywell shell; drywell head; drywell shell in 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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon steel and carbon steel - dissimilar metal welds electrical and mechanical penetrations, penetration flued heads. bellows and sleeves, and steel elements of the drywell shell, head, embedded and sandpocket regions (accessible and inaccessible areas) exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage loss of material of the carbon steel elements of the downcomers and drywell shell, head, embedded and sandpocket regions exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation.
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 PBAPS Mark I steel containment. The Item Number is applicable only to BWR concrete containments with steel liner plates.
3.5.1-038	Steel elements: suppression chamber shell (interior surface)	Cracking due to SCC	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to BWR Mark III containments. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-039	Steel elements: vent line bellows	Cracking due to SCC	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.32) program and ASME Section XI, Subsection IWE (B.2.1.30) program will be used to manage cracking of the stainless steel elements: vent line, header, and bellows exposed to air - indoor uncontrolled in the Containment Structure. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.30) program implementation. The Structures Monitoring (B.2.1.34) program has been substituted and will be used to manage cracking of the stainless steel elements of the refueling bellows assemblies exposed to air – indoor uncontrolled in the Containment Structure. See Subsection 3.5.2.2.1.6.
3.5.1-040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Not Applicable. This Item Number is not applicable to the PBAPS Mark I steel containment. The Item Number is applicable only to BWR Mark II 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Consistent with NUREG-2191. This Item Number has been used for embedded steel components within reinforced concrete in the Containment Structure (drywell shell and drywell support skirt) and Reactor Building (liner, liner anchors, and integral attachments). Steel components contained within concrete do not require an aging management program as described in the SLR-GALL report.
3.5.1-042	Groups 1-3, 5, 7-9: concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage loss of material (spalling, scaling) and cracking of the reinforced concrete in inaccessible areas exposed to an air - outdoor environment in Group 2, 3, and 9 structures. PBAPS used Group 2 Item Numbers instead of Group 1 or 5 Item Numbers. PBAPS does not have Group 7 and 8 structures. See Subsection 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 Programs	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	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage cracking of the reinforced concrete (inaccessible areas). This Item Number is also used for accessible areas of basemat, foundation, subfoundation concrete elements, as well as tank foundations, curbs, duct banks, manholes, and handholes, and equipment supports and foundations. This Item Number is used for reinforced concrete exposed to air - indoor uncontrolled, air - outdoor, and groundwater/soil in all structures except for Group 6 structures. Group 6 structures are addressed under Item Number 3.5.1-050. See Subsection 3.5.2.2.2.1.2.
3.5.1-044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, "Structures Monitoring"	Yes	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage cracking and distortion of the reinforced concrete elements of the PBAPS structures founded soil on and exposed to a groundwater/soil environment. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-045	This Item Number is not listed in NUREG-2192.				
3.5.1-046	Groups 1-3, 5-9: concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, "Structures Monitoring"	Yes	Not Applicable. The foundation designs do not incorporate porous concrete in the sub-foundation. Since the magnitude of the total settlements is small, differential settlement distortion is insignificant for PBAPS structures. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage increase in porosity and permeability, loss of strength of the reinforced concrete basemat, foundation, subfoundation, below-grade exterior concrete (inaccessible areas), duct banks, manholes, and handholes exposed to water- flowing in Groups 2, 3, and 9 structures. PBAPS used Group 2 Item Numbers instead of Group 1 or 5 Item Numbers. PBAPS does not have Group 7 and 8 structures. This Item Number does not apply to the Group 4 concrete structures because of the Mark I containment design. See Subsection 3.5.2.2.2.1.4.
3.5.1-048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program	Yes	Not Applicable. There are no concrete structures exposed to elevated temperature (>150°F general; >200°F local) in Structures and Component Supports. See Subsection 3.5.2.2.2.2.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-049	Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage loss of material (spalling, scaling) and cracking of the reinforced concrete above-grade exterior (inaccessible areas), basemat, foundation, subfoundation (inaccessible areas), below-grade exterior (inaccessible areas), and interior (inaccessible areas) exposed to air - outdoor in Group 6 structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures. See Subsection 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 Programs	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	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage cracking of the Group 6 inaccessible, reinforced concrete exposed to air - indoor uncontrolled, air - outdoor, and groundwater/soil. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage increase in porosity and permeability, loss of strength of the reinforced concrete above-grade exterior (inaccessible areas), basemat, foundation, subfoundation (inaccessible areas), below-grade exterior (inaccessible areas), and interior (inaccessible areas) exposed to water - flowing in Group 6 structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in-scope structures. See Subsection 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	Not Applicable. There are no Group 7 or Group 8 tanks with liners exposed to water in scope for this application. See Subsection 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 Programs	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, TLAA	Not Applicable. There are no support members; welds; bolted connections; or support anchorages to building structure subject to cumulative fatigue damage due to cyclic loading in Structures and Component Supports. See Subsection 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. The Structures Monitoring (B.2.1.34) program will be used to manage cracking of grout and concrete elements exposed to air - indoor uncontrolled, air - outdoor, and groundwater/soil in all structures except for Group 6 structures, and the Component Supports commodity group.
3.5.1-055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage reduction in concrete anchor capacity in building concrete at locations of expansion and grouted anchors, and grout pads for support base plates exposed to air - indoor uncontrolled and air - outdoor in the Component Supports commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program will be used to manage loss of material of the reinforced concrete in above-grade exterior, below-grade exterior, basemat, foundation, subfoundation, and Interior areas exposed to water - flowing in the Circulating Water Pump Structure and Emergency Cooling Tower and Reservoir. The Structures Monitoring (B.2.1.34) program has been substituted and will be used to manage loss of material of the Concrete: Basemat, Foundation, Subfoundation (inaccessible areas), exposed to water - flowing in the Turbine Building and Main Control Room Complex. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam) will be used to manage loss of material of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to water flowing environment in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 (B.2.1.31) program will be used to manage loss of mechanical function of the carbon steel constant and variable load spring hangers, guides, stops and sliding surfaces for ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled in the Component Supports commodity group. The Structures Monitoring (B.2.1.34) program has been substituted and will be used to manage loss of mechanical function of the supports and sliding surfaces of the supports and components exposed to air – indoor uncontrolled in the Containment Structure, Radwaste Building and Reactor Auxiliary Bay, and the Component Supports commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-058	Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program because of the plant design. There are no water control structures, such as dams, slopes, canals, submerged emergency canals, and other raw water-control structures associated with emergency cooling water systems or flood protection in scope for this program. The areas inside of the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir are monitored for sedimentation and debris. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam) will be used to manage loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to raw water environment in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-059	Group 6: concrete (accessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program will be used to manage cracking, loss of bond, and loss of material of accessible and inaccessible reinforced concrete elements of curbs, above-grade exterior, basemat, foundation, subfoundation, below-grade exterior, interior, equipment supports and foundations, hatches/plugs, and precast concrete panels exposed to air- indoor uncontrolled, air- outdoor, and raw water in the Group 6 structures. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam) will be used to manage cracking, loss of bond, and loss of material of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to air- outdoor and raw water environments in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 (B.2.1.35) program will be used to manage loss of material (spalling, scaling) and cracking of accessible reinforced concrete above-grade exterior, basemat, foundation, subfoundation, below-grade exterior, interior, hatches/plugs, and precast beams and panels exposed to air- outdoor in the Group 6 structures. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam) will be used to manage loss of material (spalling, scaling) and cracking of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to air-outdoor environment in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program will be used to manage increase in porosity and permeability, loss of strength of accessible reinforced concrete above-grade exterior, basemat, foundation, subfoundation, below-grade exterior, and interior and exposed to water-flowing in the Group 6 structures. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam)will be used to manage increase in porosity and permeability, loss of strength of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to water flowing environment in the Station Blackout Structure and Foundations.
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	The Wooden Pole (B.2.2.1) program has been substituted and will be used to manage loss of material and change in material properties of treated wood poles exposed to air – outdoor and soil in the Electrical Commodities commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-063	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage increase in porosity and permeability, loss of strength of the grout and reinforced concrete basemat, foundation, subfoundation (accessible areas), interior, equipment supports and foundations, and penetration Seals exposed to water - flowing in Groups 2, 3, and 9 structures, and the Hazard Barriers and Elastomers commodity group. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which are part of the Group 2 Reactor Buildings. Group 7 and 8 structures are not applicable to PBAPS.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**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. The Structures Monitoring (B.2.1.34) program will be used to manage cracking and loss of material of the grout and reinforced concrete elements of the condensate storage tank foundation, curbs, above-grade exterior (accessible areas), basemat, foundation, subfoundation (accessible areas), interior (accessible areas), equipment supports and foundations, hatches/plugs, manholes, handholes & duct banks, penetration seals, and precast beams and panels exposed to air- outdoor in the Group 2, 3, and 9 structures, and the Hazard Barriers and Elastomers commodity group. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which are part of the Group 2 Reactor Buildings. Group 7 and 8 structures are not applicable to PBAPS.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage cracking, loss of bond, and loss of material at reinforced concrete elements for Groups 2, 3, and 9: at inaccessible areas of concrete below-grade exterior, basemat, foundation, and subfoundation; and Group 6 and other concrete for Hazard Barriers and Component Supports in accessible and inaccessible areas above-grade and below-grade exterior, interior, basemat, foundation, and subfoundation as well tank foundations, curbs, duct banks, equipment supports and foundations, manholes, handholes, and duct banks, penetration seals, and at locations of expansion and grouted anchors and grout pads; exposed to air - indoor uncontrolled, air - outdoor, and groundwater/soil environments. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which are part of the Group 2 Reactor Buildings. Group 7 and 8 structures are not applicable to PBAPS.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage cracking, loss of bond, and loss of material of Groups 2, 3, 4, and 9 concrete, grout, and reinforced concrete elements: for concrete above-grade exterior (accessible areas and inaccessible areas); concrete: basemat, foundation, and subfoundation (accessible areas and inaccessible areas); concrete: Interior, (accessible areas and inaccessible areas); and other concrete for curbs, equipment supports and foundations, hatches/plugs, manholes, handholes, and duct banks, and precast concrete- beams and panels; as well as grout for penetration seals for the Hazard Barriers and Elastomers commodity group. These areas are exposed to air - indoor uncontrolled and air - outdoor environments. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which are part of the Group 2 Reactor Buildings. Group 7 and 8 structures are not applicable to PBAPS.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage increase in porosity and permeability, cracking, and loss of material (spalling, scaling) of the reinforced concrete components for Groups 2, 3, and 9: concrete below-grade exterior (inaccessible areas), basemat, foundation, subfoundation (accessible and inaccessible areas); Group 6 inaccessible concrete elements; as well as other concrete such as tank foundations, curbs, equipment supports and foundations, manholes, and handholes, and duct banks exposed to groundwater/soil. At PBAPS, the there are no stand-alone Group 1 or 5 structures, which are part of the Group 2 Reactor Buildings. Group 7 and 8 structures are not applicable to PBAPS. This mechanism is only associated with exposure to groundwater at PBAPS so it does not apply to Group 4 concrete components, which are not exposed to groundwater.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.31) program will be used to manage cracking of the high strength low alloy steel bolting with yield strength of 150 ksi or greater used in supports for ASME Class 1, Class 2, and Class 3 piping and components exposed to air - indoor uncontrolled in the Component Supports commodity group.
3.5.1-069	This Item Number is not listed in NUREG-2192.				
3.5.1-070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls (B.2.1.33) program will be used to manage cracking of the interior and exterior masonry walls and hazard barriers exposed to air - indoor uncontrolled and air - outdoor in the Administration Building and Shop, Circulating Water Pump Structure, Dewatering Building, Emergency Cooling Tower and Reservoir, Radwaste Building and Reactor Auxiliary Bay, Reactor Building, Recombiner Building, Turbine Building and Main Control Room Complex, and Hazard Barriers and Elastomers commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking of the concrete block masonry walls exposed to air - outdoor in the Administration Building and Shop, Dewatering Building, and Recombiner Building.
3.5.1-072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of sealing of the aluminum, elastomer, galvanized steel, and stainless steel door seals, expansion joints, hazard barriers, penetration seals, roofing, seals, gaskets, and moisture barriers, and spent fuel pool gates seals exposed to air - indoor uncontrolled, air - outdoor, groundwater/soil, raw water, and treated water in the Hazard Barriers and Elastomers commodity group.
3.5.1-073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance (B.2.1.36) program will be used to manage loss of coating or lining integrity of the Service Level I Coatings exposed to treated water in the Containment 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 Programs	Further Evaluation Recommended	Discussion
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. The Structures Monitoring (B.2.1.34) program will be used to manage the loss of mechanical function of the Lubrite sliding support bearings and sliding support surfaces in the Component Supports commodity group for cable trays, conduit, HVAC system components and ducts, tube track, instrument tubing, non-ASME piping and components, emergency diesel generator, and other mechanical equipment, as well as sliding support bearings and sliding support surfaces for the Turbine Building and Main Control Room Complex, exposed to air- indoor uncontrolled.
3.5.1-075	Sliding surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.31) program will be used to manage the loss of mechanical function of the Lubrite sliding surfaces in the Component Supports commodity group for supports for ASME Class 1 piping and components, ASME Class 2 and 3 piping and components, and for ASME Class MC components, exposed to air- indoor uncontrolled.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-076	Sliding surfaces: radial beam seats in BWR drywell	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, "Structures Monitoring"	No	Not Applicable. There are no Lubrite or similar sliding surfaces for BWR radial beam seats exposed to air- indoor uncontrolled in the drywell. Refer to Item Number 3.5.1-057 and 3.5.1-077 for applicable Item Numbers for the components and materials at PBAPS.
3.5.1-077	Steel components: all structural steel	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of the carbon steel and ductile iron for concrete embedments; doors; equipment supports and foundations; hatches and plugs; hazard barriers; manholes, handholes, and duct banks; metal components; panels, racks, frames, cabinets, and other enclosures; penetration seals and sleeves; pipe whip restraints and jet impingement shields; roofing, seals, gaskets, and moisture barriers; sliding surfaces; steel components; steel elements: liner, liner anchors, integral attachments; structural miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, decking, missile barrier, shielding, siding, vents; and tube track exposed to air- indoor uncontrolled and air- outdoor in the Administration Building and Shop, Boiler House, Circulating Water Pump 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 Programs**	**Further Evaluation Recommended**	**Discussion**
					Containment Structure, Dewatering Building, Diesel Generator Building, Emergency Cooling Tower and Reservoir, Nitrogen Storage Building, Outdoor Electric Switchgear, North Substation, Radwaste Building and Reactor Auxiliary Bay, Reactor Building, Recombiner Building, Stack, Station Blackout Structure and Foundations, Turbine Building and Main Control Room Complex, and Yard Structures, as well as the commodity groups for Electrical and Instrumentation Enclosures and Raceways; Hazard Barriers and Elastomers; and Miscellaneous Steel.
3.5.1-078	Stainless steel fuel pool liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	AMP XI.M2, "Water Chemistry," and monitoring of the spent fuel pool water level and leakage from the leak chase channels.	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking and loss of material of the stainless steel bolting, embedments, spent fuel pool gates, liner, liner anchors, and integral attachments exposed to treated water in the Reactor Building. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of the carbon steel penetration seals, penetration sleeves, and piles exposed to groundwater/soil in the Administration Building and Shop, Diesel Generator Building, and Hazard Barriers and Elastomers commodity group.
3.5.1-080	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of carbon and low alloy steel structural bolting, and anchors in concrete for structures and structural elements, such as hazard barriers (penetrations through the sacrificial shield wall), panels, racks, frames, cabinets, and other enclosures, structural miscellaneous - siding, vents (blowout panels), and supports 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-081	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.31) program will be used to manage loss of material of the carbon and low alloy steel structural bolting and the high strength low alloy structural steel bolting with yield strength of 150 ksi or greater in supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops, supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure, supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops, supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure, supports for ASME Class MC components: constant and variable load spring hangers; guides; stops, and supports for ASME Class MC components: support members; welds; bolted connections; support anchorage to building structure exposed to air - indoor uncontrolled and air - outdoor in the Component Supports commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of the carbon and low alloy steel and galvanized steel structural bolting and galvanized steel support members exposed to air - outdoor in the Yard Structures, and Component Supports commodity group.
3.5.1-083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program will be used to manage loss of material of carbon and low alloy steel bolting, and carbon steel and gray cast iron anchors used for equipment supports and foundations, and metal components for the sluice gates and fill supports exposed to air- indoor uncontrolled, air- outdoor, and raw water in the Circulating Water Pump Structure and Emergency Cooling Tower and Reservoir. Consistent with NUREG-2191. FERC Inspections of the Conowingo Hydroelectric Plant (Dam)will be used to manage loss of material of steel used for the Conowingo Hydroelectric Plant (Dam) exposed to air-outdoor and water flowing environments in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-084	This Item Number is not listed in NUREG-2192.				
3.5.1-085	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWF (B.2.1.31) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel structural bolting used for supports for ASME Class 2 and 3 piping and components and supports for ASME Class MC components exposed to treated water and in the Component Supports commodity group. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage loss of material of the stainless steel structural bolting exposed to treated water in the Fuel Handling System.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 (B.2.1.31) program will be used to manage loss of material of the galvanized steel bolting and galvanized steel supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure exposed to air- outdoor in the Component Supports commodity group.
3.5.1-087	Structural bolting	Loss of preload due to self-loosening	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.31) program will be used to manage loss of preload of the brass, carbon and low alloy steel, galvanized steel, and stainless steel bolting, and high strength low alloy steel bolting with yield strength of 150 ksi or greater used in ASME Class 1,2, Class 3, MC supports exposed to air - indoor uncontrolled, air - outdoor, raw water, and treated water in the Component Supports commodity group.
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of preload for structural bolting and anchors made from aluminum, brass, carbon and low alloy steel, galvanized steel, stainless steel;

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
					metal components- cable trays and wireway gutters; panels, racks, frames, cabinets, and other enclosures; roofing; spent fuel pool gates; structural miscellaneous – siding and vents; bolted connections for supports for cable trays, conduit, HVAC components and ducts, tube track, instrument tubing, non-ASME piping and components, sliding support bearings and surfaces, emergency diesel generator, and other mechanical equipment; bolted connections for supports for platforms, pipe whip restraints, jet impingement shields, masonry walls, and other structures; bolted connections for supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation exposed to air- indoor uncontrolled, air-outdoor, raw water, and treated water in the Administration Building and Shop, Boiler House, Circulating Water Pump Structure, Containment Structure, Dewatering Building, Diesel Generator Building, Emergency Cooling Tower and Reservoir, Nitrogen Storage Building, Outdoor Electric Switchgear, North Substation, Radwaste Building and Reactor Auxiliary Bay, Reactor Building, Recombiner Building, Stack, Station Blackout Structure and Foundations, Turbine Building and Main Control Room Complex, and Yard Structures, as well as the commodity groups for Component Supports, Electrical and Instrumentation Enclosures and

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					Raceways, Hazard Barriers and Elastomers, and Miscellaneous Steel,. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage loss of preload of the stainless steel structural bolting exposed to air – indoor uncontrol and treated water in the Fuel Handling System.
3.5.1-089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not Applicable. Item Number 3.5.1-089 is applicable to PWRs only and is not used for PBAPS.

Table 3.5.1	Summary of Aging Management Evaluations for the Containments, Structures and Component Supports				
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWF (B.2.1.31) program and Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon and low alloy steel structural bolting, and stainless steel used for ASME Class 2 and 3 supports exposed to treated water in the Component Supports commodity group. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage loss of material for the stainless steel cranes and hoists exposed to treated water in the Fuel Handling System. The Structures Monitoring (B.2.1.34) program has been substituted and will be used to manage loss of material of the carbon steel hatches/plugs exposed to treated water in the Reactor Building.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-091	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.31) program will be used to manage loss of material of the carbon steel ASME Class 1, 2, 3, and MC supports exposed to air - indoor uncontrolled and air - outdoor in the Component Supports commodity group.
3.5.1-092	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of the carbon steel supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, racks, panels, cabinets, mechanical equipment, electrical and instrumentation enclosures exposed to air - indoor uncontrolled and air - outdoor in the Component Supports commodity group.
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. The Structures Monitoring (B.2.1.34) program will be used to manage loss of material of galvanized steel members and bolting of anchors and embedments in concrete; conduit, expansion joints; metal components- cable trays and wireway gutters, poles, and outdoor structures; panels, racks, frames, cabinets, and other enclosures; roofing; steel components;

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
					structural miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, decking, and vents; supports for cable trays, conduit, HVAC components and ducts, tube track, instrument tubing, non-ASME piping and components, emergency diesel generator, and other mechanical equipment exposed to air- outdoor in the Administration Building and Shop, Boiler House, Circulating Water Pump Structure, Dewatering Building, Emergency Cooling Tower and Reservoir, Nitrogen Storage Building, Outdoor Electric Switchgear, North Substation, Radwaste Building and Reactor Auxiliary Bay, Reactor Building, Recombiner Building, Stack, Station Blackout Structure and Foundations, Turbine Building and Main Control Room Complex, and Yard Structures, as well as the commodity groups for Component Supports, Electrical and Instrumentation Enclosures and Raceways, Hazard Barriers and Elastomers, and Miscellaneous Steel.
3.5.1-094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, "ASME Section XI, Subsection IWF," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.1.34) program will be used to manage reduction or loss of isolation function of the elastomer supports for vibration isolation elements exposed to air- indoor uncontrolled in the Component Supports commodity group.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191.
3.5.1-096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program will be used to manage cracking of the reinforced concrete curbs; equipment supports and foundations; hatches and plugs; precast panels; as well accessible and inaccessible areas of concrete above-grade exterior, basemat, foundations, and subfoundations, below-grade exterior, and interior concrete exposed to air- indoor uncontrolled, air–outdoor, and raw water in the Group 6 structures. FERC Inspections of the Conowingo Hydroelectric Plant (Dam)have been substituted and will be used to manage cracking of reinforced concrete used for the Conowingo Hydroelectric Plant (Dam) exposed to air- outdoor and raw water environments in the Station Blackout Structure and Foundations.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Yes	The Structures Monitoring (B.2.1.34) program will be used to manage reduction of strength and loss of mechanical properties of the reinforced concrete elements exposed to air - indoor uncontrolled in Group 4 structure. See Subsection 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 component, material, and environment combination is addressed by Item Number 3.5.1-099.
3.5.1-099	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking and loss of material of the stainless steel structural bolting and stainless steel elements for ASME Class 1, 2, and 3 supports exposed to air - indoor uncontrolled and air - outdoor in the Containment Structure and Component Supports commodity group. See Subsection 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 Programs	Further Evaluation Recommended	Discussion
3.5.1-100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S6, "Structures Monitoring," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Consistent with NUREG-2191. The One-Time Inspection (B.2.1.21) program will be used to manage cracking and loss of material of aluminum and stainless steel members and bolting, for embedments; conduit; equipment storage racks, expansion joints, fuel storage racks, hatches and plugs, hazard barriers, metal components- cable trays, wireway gutters, poles, and outdoor structures; insulation and insulation jacketing; panels, racks, frames, cabinets, and other enclosures; penetration seals; roofing; spent fuel pool gates; steel elements- liner, liner anchors, and integral attachments; structural miscellaneous - shielding, siding, and vents; supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components exposed to air- indoor uncontrolled and air-outdoor environments in the Circulating Water Pump Structure, Outdoor Electric Switchgear, North Substation, Radwaste Building and Reactor Auxiliary Bay, Reactor Building, Recombiner Building, Stack, Station Blackout Structure and Foundations, and Turbine Building and Main Control Room Complex, as well as commodity groups Component Supports, Electrical and Instrumentation Enclosures and Raceways, Hazard Barriers and Elastomers, Insulation, and Miscellaneous Steel.

Table 3.5.1 Summary of Aging Management Evaluations for the Containments, Structures and Component Supports					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
					The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been substituted and will be used to manage cranes, hoists, and their associated structural bolting for loss of material in aluminum and cracking and loss of material in stainless steel exposed to air – indoor uncontrolled for the Fuel Handling System. See Subsection 3.5.2.2.2.4.

Table 3.5.2-1
Administration Building and Shop
Summary of Aging Management Evaluation

Table 3.5.2-1 Administration Building and Shop

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Concrete: Above-grade exterior (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-1 Administration Building and Shop (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Below-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A

Table 3.5.2-1 Administration Building and Shop (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (accessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Masonry walls: Exterior	Structural Support	Concrete Block	Air - Outdoor	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of Material (Spalling, Scaling) and Cracking	Masonry Walls (B.2.1.33)	III.A3.TP-34	3.5.1-071	A
Masonry walls: Interior	Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
Piles	Structural Support	Carbon Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-219	3.5.1-079	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-1 Administration Building and Shop (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-2
Boiler House
Summary of Aging Management Evaluation

Table 3.5.2-2 Boiler House

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-2 Boiler House (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-2 Boiler House (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Metal components	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Precast Concrete-Beams and Panels	Shelter and Protection	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking	Shelter and Protection	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A

Table 3.5.2-2 Boiler House (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Decking	Shelter and Protection	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Structural Miscellaneous - Siding	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-2 Boiler House (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-3
Circulating Water Pump Structure
Summary of Aging Management Evaluation

Table 3.5.2-3 Circulating Water Pump Structure

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-107	3.5.1-067	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support Water Retaining Boundary	Reinforced concrete	Raw Water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Below-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-107	3.5.1-067	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Interior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
Equipment supports and foundations (Sluice Gate supports and guides)	Structural Support	Carbon Steel	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Equipment supports and foundations (Sluice Gate supports and guides)	Structural Support	Carbon and Low Alloy Steel Bolting	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
		Gray Cast Iron	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	A
Equipment supports and foundations (Traveling Water Screen supports)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
			Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
Hatches/Plugs	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Bronze Bolting	Air - Indoor Uncontrolled	None	None	IV.E.R-453	3.1.1-137	C
			Air - Outdoor	None	None	IV.E.R-453	3.1.1-137	C
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Ductile Iron	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatches/Plugs	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
Masonry walls: Interior	Shelter and Protection Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A6.T-12	3.5.1-070	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal components (includes steel plates)	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Metal components (sluice gate)	Water Retaining Boundary	Gray Cast Iron	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	C
Metal components (sluice gate- seat facing)	Water Retaining Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.A-473b	3.3.1-160	E, 1
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-196	3.3.1-034	E, 1
					Selective Leaching (B.2.1.22)	VII.C1.A-47	3.3.1-072	C
Precast Concrete-Beams and Panels (Precast Panels)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Precast Concrete-Beams and Panels (Precast Panels)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking	Shelter and Protection Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-3 Circulating Water Pump Structure (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is substituted to manage the applicable aging effects for this component type, material, and environment combination.

Table 3.5.2-4

Component Supports

Summary of Aging Management Evaluation

Table 3.5.2-4 Component Supports

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 1 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.1.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.1.TP-42	3.5.1-055	A
Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.T-28	3.5.1-057	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-229	3.5.1-087	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	A
Supports for ASME Class 1 piping and components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.T-28	3.5.1-057	C, 1
		Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-45	3.5.1-075	A
Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.T-24	3.5.1-091	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-229	3.5.1-087	A
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-41	3.5.1-068	A
				Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-226	3.5.1-081	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-229	3.5.1-087	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.1.T-36a	3.5.1-099	C
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-229	3.5.1-087	A
Supports for ASME Class 2 and 3 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.2.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.2.TP-42	3.5.1-055	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-28	3.5.1-057	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-10	3.5.1-090	C
					Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-10	3.5.1-090	C
					Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Brass Bolting	Air - Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
				None	None	IV.E.R-453	3.1.1-137	C
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-28	3.5.1-057	C, 2

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-45	3.5.1-075	A
Supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-24	3.5.1-091	A
			Air - Outdoor	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.T-24	3.5.1-091	A
			Raw Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.E5.A-413	3.3.1-137	E, 3
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-10	3.5.1-090	C
					Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
			Air - Outdoor	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-10	3.5.1-090	C
					Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B1.2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-235	3.5.1-086	C
			Raw Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.E5.A-413	3.3.1-137	E, 3
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
				None	None	III.B1.2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-235	3.5.1-086	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
			Raw Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.E5.A-413	3.3.1-137	E, 3
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
		High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.1.TP-41	3.5.1-068	A
				Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-226	3.5.1-081	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
			Raw Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.E5.A-413	3.3.1-137	E, 3
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-232	3.5.1-085	C
					Water Chemistry (B.2.1.2)	III.B1.2.TP-232	3.5.1-085	D
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.2.T-36a	3.5.1-099	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-232	3.5.1-085	A
					Water Chemistry (B.2.1.2)	III.B1.2.TP-232	3.5.1-085	B
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.2.TP-229	3.5.1-087	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class MC components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.3.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B1.3.TP-42	3.5.1-055	A
Supports for ASME Class MC components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.T-28	3.5.1-057	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
Supports for ASME Class MC components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.T-24	3.5.1-091	C
				Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.T-28	3.5.1-057	C, 2
		Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-45	3.5.1-075	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class MC components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.T-24	3.5.1-091	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.H1.A-413	3.3.1-137	E, 3
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-226	3.5.1-081	A
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.H1.A-413	3.3.1-137	E, 3
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
				None	None	III.B3.TP-8	3.5.1-095	C
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	VII.H1.A-413	3.3.1-137	E, 3
				Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
		Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-232	3.5.1-085	C
					Water Chemistry (B.2.1.2)	III.B1.3.TP-232	3.5.1-085	D
		Stainless Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-232	3.5.1-085	A
					Water Chemistry (B.2.1.2)	III.B1.3.TP-232	3.5.1-085	B

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for ASME Class MC components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.31)	III.B1.3.TP-229	3.5.1-087	A
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B2.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B2.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B2.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B2.TP-42	3.5.1-055	A
			Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-27	3.5.1-065	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	C

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: sliding support bearings; sliding support surfaces	Structural Support	Brass Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
				None	None	IV.E.R-453	3.1.1-137	C
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B1.3.T-28	3.5.1-057	E, 4
		Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B2.TP-46	3.5.1-074	A
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Aluminum Bolting	Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-43	3.5.1-092	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-43	3.5.1-092	A
			Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 5
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
			Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 5
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
				None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.H1.A-413	3.3.1-137	E, 5
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
			Treated Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.H1.A-413	3.3.1-137	E, 5
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure (inside manholes)	Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
			Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 5
		Galvanized Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure (inside manholes)	Structural Support	Galvanized Steel Bolting	Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 5
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B2.TP-261	3.5.1-088	A
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B4.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B4.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B4.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B4.TP-42	3.5.1-055	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: sliding support bearings; sliding support surfaces	Structural Support	Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B4.TP-46	3.5.1-074	A
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-43	3.5.1-092	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-43	3.5.1-092	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B4.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B4.TP-261	3.5.1-088	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B4.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-6	3.5.1-093	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B4.TP-261	3.5.1-088	A
				None	None	III.B4.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B4.TP-261	3.5.1-088	A
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: vibration isolation elements	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B4.TP-43	3.5.1-092	A
		Elastomer	Air - Indoor Uncontrolled	Reduction or Loss of Isolation Function	Structures Monitoring (B.2.1.34)	III.B4.TP-44	3.5.1-094	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B5.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B5.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B5.TP-42	3.5.1-055	A
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B5.TP-43	3.5.1-092	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B5.TP-43	3.5.1-092	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B5.TP-248	3.5.1-080	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B5.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B5.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B5.TP-261	3.5.1-088	A
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-43	3.5.1-092	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-43	3.5.1-092	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B3.TP-261	3.5.1-088	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B3.TP-261	3.5.1-088	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B3.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-274	3.5.1-082	C
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.B3.TP-261	3.5.1-088	A
				None	None	III.B3.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B3.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.B3.TP-261	3.5.1-088	A

Table 3.5.2-4 Component Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Grout	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B3.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B3.TP-42	3.5.1-055	A
		Reinforced concrete	Air - Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B3.TP-42	3.5.1-055	A
			Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.34)	III.B3.TP-42	3.5.1-055	A
			Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-27	3.5.1-065	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	C

Table 3.5.2-4 Component Supports (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The stabilizer at top of reactor vessel allows for vertical movements and does not use Lubrite or similar material but instead consists of steel to steel connections.

2. Support designs allow for movements and do not use Lubrite or similar material but instead consist of steel to steel connections.

3. The ASME Section XI, Subsection IWF (B.2.1.31) program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

4. Support designs allow for movements and do not use Lubrite or similar material but instead consist of steel to steel connections. The Structures Monitoring (B.2.1.34) program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

5. The Structures Monitoring (B.2.1.34) program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

Table 3.5.2-5
Containment Structure
Summary of Aging Management Evaluation

Table 3.5.2-5 Containment Structure

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Containment Closure)	Structural Pressure Barrier	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-148	3.5.1-031	B
				Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-150	3.5.1-030	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.3.T-36a	3.5.1-099	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.3.T-36a	3.5.1-099	C
				Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-150	3.5.1-030	B
	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-148	3.5.1-031	B
				Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-150	3.5.1-030	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B1.3.T-36a	3.5.1-099	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B1.3.T-36a	3.5.1-099	C

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Containment Closure)	Structural Support	Stainless Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-150	3.5.1-030	B
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A4.TP-261	3.5.1-088	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A4.TP-261	3.5.1-088	A
				None	None	III.B1.1.TP-8	3.5.1-095	C
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A4.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	C
Concrete: Interior (accessible areas- drywell floor and reactor pedestal)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Spalling, Corrosion of Rebar	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A4.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas- drywell floor and reactor pedestal)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Spalling, Corrosion of Rebar	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A4.TP-204	3.5.1-043	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: near reactor vessel (sacrificial shield wall)	Direct Flow Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Spalling, Corrosion of Rebar	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A4.TP-25	3.5.1-054	A
				Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.34)	III.A4.T-35	3.5.1-097	A, 1
	HELB/MELB Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Spalling, Corrosion of Rebar	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A4.TP-25	3.5.1-054	A
				Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.34)	III.A4.T-35	3.5.1-097	A, 1
	Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Spalling, Corrosion of Rebar	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A4.TP-25	3.5.1-054	A
				Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.34)	III.A4.T-35	3.5.1-097	A, 1
Doors (in sacrificial shield wall)	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
	Shielding Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Hazard Barrier (penetrations through the sacrificial shield wall)	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hazard Barrier (penetrations through the sacrificial shield wall)	Shielding	Grout	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A4.TP-26	3.5.1-066	A
	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A4.TP-261	3.5.1-088	A
Penetration - Containment Electrical	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment Electrical	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Elastomer	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
Penetration - Containment Mechanical	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment Mechanical	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
Penetration - Containment Mechanical (flued heads and bellows)	Expansion/ Separation	Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment Mechanical (flued heads and bellows)	Expansion/ Separation	Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment Mechanical (flued heads and bellows)	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
Penetration - Containment Sleeves	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment Sleeves	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 2
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Carbon Steel; Dissimilar Metal Welds	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-38	3.5.1-010	B

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration - Containment-spares, access manholes, inspection ports	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-37	3.5.1-027	B
				Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-36	3.5.1-035	B
Personnel airlock, CRD hatch, equipment hatch	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.C-16	3.5.1-028	B
Personnel airlock, CRD hatch, equipment hatch (locks, hinges, closure mechanisms)	Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Leaktightness	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-39	3.5.1-029	B
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Leaktightness	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-39	3.5.1-029	B

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pipe Whip Restraints and Jet Impingement Shields	Direct Flow Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
	Pipe Whip Restraint	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	Shelter and Protection	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	10 CFR Part 50, Appendix J (B.2.1.32)	II.B4.CP-41	3.5.1-033	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B4.CP-40	3.5.1-026	B
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B1.1.TP-8	3.5.1-095	C
Service Level I Coating	Maintain Adhesion	Coatings	Air - Indoor Uncontrolled	Loss of Coating or Lining Integrity	Protective Coating Monitoring and Maintenance (B.2.1.36)	II.B4.CP-152	3.5.1-034	A
			Treated Water	Loss of Coating or Lining Integrity	Protective Coating Monitoring and Maintenance (B.2.1.36)	III.A4.TP-301	3.5.1-073	A
Sliding surfaces	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
				Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B1.3.T-28	3.5.1-057	E, 3
Steel components: sacrificial shield wall and stabilizer	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Steel components: sacrificial shield wall and stabilizer (vent ducts)	Direct Flow	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Steel components: structural steel (seal plate)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A5.TP-302	3.5.1-077	A, 4
	Water Retaining Boundary	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A5.TP-302	3.5.1-077	A, 4
Steel elements: Downcomers	Direct Flow Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2
				Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-109	3.5.1-007	B
						II.B1.1.C-23	3.5.1-036	B
			Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-109	3.5.1-007	B
Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-43	3.5.1-035	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-43	3.5.1-035	B
						II.B1.1.C-23	3.5.1-036	B
Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-43	3.5.1-035	C
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-43	3.5.1-035	D

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	Shelter and Protection Structural Pressure Barrier Structural Support	Carbon Steel	Concrete	None	None	II.B1.1.CP-44	3.5.1-041	C
Steel elements: Drywell - support skirt (inaccessible areas)	Structural Support	Carbon Steel	Concrete	None	None	II.B1.1.CP-44	3.5.1-041	A
Steel elements: Liner, liner anchors, integral attachments - accessible areas (reactor pedestal and sacrificial shield wall)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Steel elements: Liner, liner anchors, integral attachments - inaccessible areas (reactor pedestal and sacrificial shield wall)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A4.TP-302	3.5.1-077	A
Steel elements: Refueling Bellows assemblies	Water Retaining Boundary	Stainless Steel	Air - Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.1.34)	II.B1.1.CP-50	3.5.1-039	E, 4, 5
Steel elements: Torus - shell	Structural Pressure Barrier Structural Support Water Retaining Boundary	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-48	3.5.1-006	A

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: Torus - shell	Structural Pressure Barrier Structural Support Water Retaining Boundary	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-48	3.5.1-006	B
			Treated Water	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-48	3.5.1-006	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-48	3.5.1-006	B
Steel elements: Torus - shell, ring girders	Structural Pressure Barrier Structural Support Water Retaining Boundary	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-109	3.5.1-007	B
			Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-109	3.5.1-007	B
Steel elements: Vent line, header, and bellows (accessible areas)	Direct Flow Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
				Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2
	Expansion/ Separation	Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-50	3.5.1-039	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-50	3.5.1-039	B

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: Vent line, header, and bellows (accessible areas)	Expansion/ Separation	Stainless Steel	Air - Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2
	Structural Pressure Barrier	Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-50	3.5.1-039	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-50	3.5.1-039	B
				Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2
Steel elements: Vent line, header, and bellows (inaccessible areas)	Direct Flow Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
				Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2
	Expansion/ Separation	Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-50	3.5.1-039	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-50	3.5.1-039	B
				Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2

Table 3.5.2-5 Containment Structure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: Vent line, header, and bellows (inaccessible areas)	Structural Pressure Barrier	Stainless Steel	Air - Indoor Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-49	3.5.1-027	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-49	3.5.1-027	B
					10 CFR Part 50, Appendix J (B.2.1.32)	II.B1.1.CP-50	3.5.1-039	A
					ASME Section XI, Subsection IWE (B.2.1.30)	II.B1.1.CP-50	3.5.1-039	B
				Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 2

Table 3.5.2-5 Containment Structure (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Structures Monitoring (B.2.1.34) program is used to manage the aging effect of reduction of strength due to irradiation for this component type, material, and environment combination.

2. The TLAA designation in the Aging Management Programs column indicates fatigue of this component is evaluated in Section 4.6.

3. The sliding supports and bearings for drywell steel beams do not use Lubrite or similar material but are instead steel to steel connections. The Structures Monitoring (B.2.1.34) program is substituted to manage the aging effects of this applicable to this component type, material, and environment combination.

4. The normal environment for this component is Air-Indoor, Uncontrolled. The treated water environment exists only on a short term basis during refueling outages, and therefore, it is not addressed separately for aging management.

5. The Structures Monitoring (B.2.1.34) program is substituted to manage the applicable aging effects for this component type, material, and environment combination.

Table 3.5.2-6
Dewatering Building
Summary of Aging Management Evaluation

Table 3.5.2-6 Dewatering Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Curbs	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Masonry walls: Exterior	Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
			Air - Outdoor	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of Material (Spalling, Scaling) and Cracking	Masonry Walls (B.2.1.33)	III.A3.TP-34	3.5.1-071	A

Table 3.5.2-6 Dewatering Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Masonry walls: Interior	Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-6 Dewatering Building (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-7
Diesel Generator Building
Summary of Aging Management Evaluation

Table 3.5.2-7 Diesel Generator Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C

Table 3.5.2-7 Diesel Generator Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-7 Diesel Generator Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Metal components	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Piles	Structural Support	Carbon Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-219	3.5.1-079	A
Steel components: structural steel	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous-Decking	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A

Table 3.5.2-7 Diesel Generator Building (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-8

Electrical and Instrumentation Enclosures and Raceways

Summary of Aging Management Evaluation

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Conduit	Shelter and Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Metal components (cable tray and wireway gutter)	Shelter and Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal components (cable tray and wireway gutter)	Shelter and Protection Structural Support	Galvanized Steel Bolting	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Panels, Racks, Frames, Cabinets, and Other Enclosures (Boxes)	Shelter and Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Panels, Racks, Frames, Cabinets, and Other Enclosures (Boxes)	Shelter and Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Aluminum Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
				None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tube Track	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Windows (in panels)	Shelter and Protection	Glass	Air - Indoor Uncontrolled	None	None	VII.J.AP-48	3.3.1-117	C

Table 3.5.2-8 Electrical and Instrumentation Enclosures and Raceways (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-9
Emergency Cooling Tower and Reservoir
Summary of Aging Management Evaluation

Table 3.5.2-9 Emergency Cooling Tower and Reservoir

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A6.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-107	3.5.1-067	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Below-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A6.TP-107	3.5.1-067	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support Water Retaining Boundary	Reinforced concrete	Raw Water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Interior (accessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (accessible areas)	Structural Support	Reinforced concrete	Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
	Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A
				Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-36	3.5.1-060	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	A
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (accessible areas)	Water Retaining Boundary	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-37	3.5.1-061	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Concrete: Interior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (inaccessible areas)	Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-220	3.5.1-050	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A6.TP-110	3.5.1-049	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.TP-104	3.5.1-065	A
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-38	3.5.1-059	C
				Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-34	3.5.1-096	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A6.TP-109	3.5.1-051	A
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.T-20	3.5.1-056	A
Cooling tower: Drift Eliminator	Direct Flow Structural Support	PVC	Air - Outdoor	Reduction in Impact Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.G.A-458	3.3.1-172	E, 1
Cooling tower: Fill	Heat Transfer	Ceramic Tile	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.I.AP-253	3.3.1-073	E, 2
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.I.AP-253	3.3.1-073	E, 2

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Cooling tower: Fill	Heat Transfer	Ceramic Tile	Raw Water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
				Flow Blockage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
	Structural Support	Ceramic Tile	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.I.AP-253	3.3.1-073	E, 2
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.I.AP-253	3.3.1-073	E, 2
			Raw Water	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
				Flow Blockage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
				Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	VII.C1.AP-250	3.3.1-030	E, 2
Hatches/Plugs	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatches/Plugs	Shelter and Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry walls: Interior	Shelter and Protection Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A6.T-12	3.5.1-070	A
	Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A6.T-12	3.5.1-070	A
Metal components	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Metal components (fill support)	Structural Support	Gray Cast Iron	Air - Outdoor	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
			Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35)	III.A6.TP-221	3.5.1-083	C
					Selective Leaching (B.2.1.22)	VII.G.A-51	3.3.1-072	C
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking (roof)	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-9 Emergency Cooling Tower and Reservoir (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is substituted to manage the applicable aging effects for this component type, material, and environment combination.

2. The ceramic tile (vitrified clay fill) in an air-outdoor and raw water environment is considered similar to concrete, concrete cylinder piping, or asbestos cement in a raw water or air-outdoor environment included in GALL for this line item and has the same aging effects. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program is substituted to manage the applicable aging effects for this component type, material, and environment combination.

Table 3.5.2-10
Hazard Barriers and Elastomers
Summary of Aging Management Evaluation

Table 3.5.2-10 Hazard Barriers and Elastomers

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Door Seal	Flood Barrier	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
	HELB/MELB Shielding	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
	Shelter and Protection Structural Pressure Barrier	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
Doors	Flood Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Doors	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shelter and Protection Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Glass	Air - Indoor Uncontrolled	None	None	VII.J.AP-48	3.3.1-117	C
			Air - Outdoor	None	None	VII.J.AP-48	3.3.1-117	C
	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Expansion Joints	Expansion/ Separation	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
		Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Hazard Barrier	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hazard Barrier	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shelter and Protection	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shielding	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
		Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
	Shielding Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Hazard Barrier (permanent lead shielding blankets)	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Fiberglass	Air - Indoor Uncontrolled	Cracking, Blistering, Loss of Material	Structures Monitoring (B.2.1.34)	VII.I.A-720	3.3.1-150	E, 1
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
Penetration Seals	Flood Barrier Shelter and Protection Structural Support	Carbon Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-219	3.5.1-079	C
			Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 1

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration Seals	Flood Barrier Shelter and Protection Structural Support	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Groundwater/Soil	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Raw Water	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Grout	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
			Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	C
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
			Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-24	3.5.1-063	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
	HELB/MELB Shielding	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Grout	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration Seals	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Grout	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
	Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Groundwater/Soil	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Raw Water	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Grout	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
			Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	C
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
			Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-24	3.5.1-063	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetration Seals	Structural Pressure Barrier	Stainless Steel	Air - Indoor Uncontrolled	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
	Water Retaining Boundary	Carbon Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-219	3.5.1-079	C
			Raw Water	Loss of Material	Structures Monitoring (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 1
		Elastomer	Groundwater/Soil	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Raw Water	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
Penetration sleeves	Flood Barrier Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-219	3.5.1-079	C
	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Roofing	Shelter and Protection Structural Pressure Barrier	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	C
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	C

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	Flood Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
	Shelter and Protection	Aluminum	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
		Galvanized Steel	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
		Stainless Steel	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
	Shelter and Protection Structural Pressure Barrier	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
		Stainless Steel	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2
			Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A, 2

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Seals, gaskets, and moisture barriers (spent fuel pool gates)	Water Retaining Boundary	Elastomer	Air - Indoor Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A
			Treated Water	Loss of Sealing	Structures Monitoring (B.2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-10 Hazard Barriers and Elastomers (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Structures Monitoring (B.2.1.34) program is substituted to manage the applicable aging effect(s) for this component type, material, and environment combination.

2. GALL includes flashing with this component type but identifies elastomers and similar materials. Metallic flashing performs the same intended function and therefore the subject line item aging effect and AMP are also appropriate for metallic materials.

Table 3.5.2-11

Insulation

Summary of Aging Management Evaluation

Table 3.5.2-11 Insulation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulation Jacketing- Thermal	Thermal Insulation Jacket Integrity	Aluminum	Air - Indoor Uncontrolled	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				None	None	III.B2.T-37a	3.5.1-100	I, 1
				Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	C
			Air - Outdoor	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				None	None	III.B2.T-37a	3.5.1-100	I, 1
				Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	C
		Fiberglass	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
		Plastic Mastic Jacketing	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A

Table 3.5.2-11 Insulation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulation Jacketing- Thermal	Thermal Insulation Jacket Integrity	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	C
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	C
Insulation- Thermal	Thermal Insulation	Calcium Silicate	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Caulking and Lagging Adhesive	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Cellular Glass	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A

Table 3.5.2-11 Insulation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulation- Thermal	Thermal Insulation	Fiberglass	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Foamed Plastic	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Insulation Cement and Finishing Cement	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Mineral Fiber	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Silicone	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
			Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	A
		Stainless Steel (Mirror Insulation)	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C

Table 3.5.2-11 Insulation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulation- Thermal	Thermal Insulation	Stainless Steel (Mirror Insulation)	Air - Indoor Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-704	3.3.1-182	C

Table 3.5.2-11 Insulation (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The aluminum jacketing is constructed of 1100, 3003, 3105, or 5005 aluminum alloy which are not susceptible to stress corrosion cracking.

Table 3.5.2-12
Miscellaneous Steel
Summary of Aging Management Evaluation

Table 3.5.2-12 Miscellaneous Steel

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
				None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Metal components	Direct Flow Shelter and Protection	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-12 Miscellaneous Steel (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal components	Direct Flow Shelter and Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
Structural Miscellaneous - Decking	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Structural Miscellaneous - Vents	Direct Flow Shelter and Protection	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-12 Miscellaneous Steel (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Vents	Direct Flow Shelter and Protection	Aluminum	Air - Outdoor	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Ductile Iron	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A

Table 3.5.2-12 Miscellaneous Steel (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-13
Nitrogen Storage Building
Summary of Aging Management Evaluation

Table 3.5.2-13 Nitrogen Storage Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Concrete: Above-grade exterior (accessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-13 Nitrogen Storage Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-24	3.5.1-063	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
			Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A

Table 3.5.2-13 Nitrogen Storage Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-13 Nitrogen Storage Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-13 Nitrogen Storage Building (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-14
Outdoor Electric Switchgear, North Substation
Summary of Aging Management Evaluation

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Aluminum Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
				None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Galvanized Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Galvanized Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
				None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Manholes, Handholes & Duct Banks	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Metal components (includes poles and outdoor structures)	Structural Support	Aluminum	Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Roofing	Shelter and Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Siding	Shelter and Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-14 Outdoor Electric Switchgear, North Substation (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-15
Radwaste Building and Reactor Auxiliary Bay
Summary of Aging Management Evaluation

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Flood Barrier HELB/MELB Shielding Missile Barrier Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	Flood Barrier HELB/MELB Shielding Missile Barrier Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Doors (special shield doors)	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Doors (special shield doors)	Missile Barrier	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Equipment supports and foundations	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Hatches/Plugs	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Masonry walls: Interior	Shielding	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
	Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal components	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Metal components (missile shield)	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Precast Concrete-Beams and Panels	Flood Barrier	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
	Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Sliding surfaces	Expansion/ Separation	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
				Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B1.3.T-28	3.5.1-057	E, 1
Steel components: structural steel	Flood Barrier	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking (floor)	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
Structural Miscellaneous - Decking (roof)	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Structural Miscellaneous - Shielding	Shielding Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Structural Miscellaneous - Siding	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Siding	Shelter and Protection	Stainless Steel Bolting	Air - Outdoor	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-15 Radwaste Building and Reactor Auxiliary Bay (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. Support design allows for movement, but does not use Lubrite or similar material, instead consists of steel to steel sliding connection. The Structures Monitoring (B.2.1.34) program is substituted to manage the aging effects of this applicable to this component type, material, and environment combination.

Table 3.5.2-16
Reactor Building
Summary of Aging Management Evaluation

Table 3.5.2-16 Reactor Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A2.A-98	3.3.1-125	C
					Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	D
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	C
			Treated Water	Cracking	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
				Loss of Material	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-23	3.5.1-064	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Flood Barrier Shelter and Protection Structural Pressure Barrier Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A2.TP-67	3.5.1-047	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Structural Pressure Barrier Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A2.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A
	HELB/MELB Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-204	3.5.1-043	A
	HELB/MELB Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-204	3.5.1-043	A
Equipment Storage Racks (inside spent fuel pool and reactor well)	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A2.A-98	3.3.1-125	C
					Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	D
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-23	3.5.1-064	A
Fuel Storage Racks (New Fuel)	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
Fuel Storage Racks (Spent Fuel)	Structural Support	Stainless Steel	Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A2.A-98	3.3.1-125	A
					Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	B
Fuel Storage Racks: neutron absorbing sheets	Absorb Neutrons	Boralcan (Rio Tinto Alcan Composite)	Treated Water	Reduction of Neutron Absorbing Capacity; Change in Dimensions and Loss of Material	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.27)	VII.A2.AP-236	3.3.1-102	A
Hatches/Plugs	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
		Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatches/Plugs	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A2.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A2.TP-23	3.5.1-064	A
Hatches/Plugs (reactor well)	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
			Treated Water	Loss of Material	Structures Monitoring (B.2.1.34)	III.B1.1.TP-10	3.5.1-090	E, 1
	Water Retaining Boundary	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
			Treated Water	Loss of Material	Structures Monitoring (B.2.1.34)	III.B1.1.TP-10	3.5.1-090	E, 1
Masonry walls: Interior	HELB/MELB Shielding	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A2.T-12	3.5.1-070	A
	Shelter and Protection Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A2.T-12	3.5.1-070	A
	Shielding	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A2.T-12	3.5.1-070	A
Metal components	Direct Flow	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal components	Direct Flow	Stainless Steel	Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A2.A-98	3.3.1-125	C
					Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	D
	Shelter and Protection	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
	Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-130	3.3.1-025	C
					Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	D
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A2.A-98	3.3.1-125	C
					Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	D

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pipe Whip Restraints and Jet Impingement Shields	HELB/MELB Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
	Pipe Whip Restraint	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
Spent fuel pool gates	Water Retaining Boundary	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-130	3.3.1-025	C
					Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	D
		Aluminum Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
			Treated Water	Loss of Material	One-Time Inspection (B.2.1.21)	VII.A4.AP-130	3.3.1-025	C
					Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	D
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Cracking	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Spent fuel pool gates	Water Retaining Boundary	Stainless Steel	Treated Water	Cracking	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
				Loss of Material	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
			Treated Water	Cracking	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
				Loss of Material	One-Time Inspection (B.2.1.21)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
Steel components: structural steel	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
Steel elements: Liner, liner anchors, integral attachments - accessible areas	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: Liner, liner anchors, integral attachments - accessible areas	Structural Support	Stainless Steel	Treated Water	Cracking	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
				Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
	Water Retaining Boundary	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Cracking	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
				Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
Steel elements: Liner, liner anchors, integral attachments - inaccessible areas	Structural Support	Carbon Steel	Concrete	None	None	II.B1.2.CP-114	3.5.1-041	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Cracking	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
				Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
	Water Retaining Boundary	Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Treated Water	Cracking	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
				Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 2
Structural Miscellaneous - Decking (floor)	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Decking (roof)	Structural Pressure Barrier	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
	Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Structural Miscellaneous - Shielding	Shielding	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
Structural Miscellaneous - Siding	Shelter and Protection Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Siding	Shelter and Protection Structural Pressure Barrier	Stainless Steel Bolting	Air - Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
Structural Miscellaneous - Vents (blowout panels)	Pressure Relief Shelter and Protection Structural Pressure Barrier	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Aluminum Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A

Table 3.5.2-16 Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Vents (blowout panels)	Pressure Relief Shelter and Protection Structural Pressure Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-302	3.5.1-077	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A2.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A2.TP-261	3.5.1-088	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-16 Reactor Building (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Structures Monitoring (B.2.1.34) program is substituted to manage the applicable aging effect(s) for this component type, material, and environment combination.

2. Water level of spent fuel pool and leakage from the leak chase channels are monitored. Therefore, the One-Time Inspection (B.2.1.21) program is not required with the Water Chemistry (B.2.1.2) program for this component type.

Table 3.5.2-17

Recombiner Building

Summary of Aging Management Evaluation

Table 3.5.2-17 Recombiner Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-17 Recombiner Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-17 Recombiner Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Hatches/Plugs	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A

Table 3.5.2-17 Recombiner Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatches/Plugs	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Masonry walls: Exterior	Shelter and Protection Structural Support	Concrete Block	Air - Outdoor	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of Material (Spalling, Scaling) and Cracking	Masonry Walls (B.2.1.33)	III.A3.TP-34	3.5.1-071	A
Masonry walls: Interior	Shelter and Protection Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
Metal components	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Precast Concrete-Beams and Panels	Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking (roof)	Shelter and Protection Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A

Table 3.5.2-17 Recombiner Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Decking (roof)	Shelter and Protection Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Structural Miscellaneous - Siding	Shelter and Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A

Table 3.5.2-17 Recombiner Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Siding	Shelter and Protection Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Structural Miscellaneous - Vents (blowout panel)	Pressure Relief Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-17 Recombiner Building (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-18
Stack
Summary of Aging Management Evaluation

Table 3.5.2-18 Stack

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A9.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A9.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A9.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A9.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Gaseous Release Path	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A
	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A

Table 3.5.2-18 Stack (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (inaccessible areas)	Gaseous Release Path	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-108	3.5.1-042	A
	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-212	3.5.1-065	A

Table 3.5.2-18 Stack (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A9.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Gaseous Release Path	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A
	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A
Concrete: Interior (inaccessible areas)	Gaseous Release Path	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-204	3.5.1-043	A

Table 3.5.2-18 Stack (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (inaccessible areas)	Gaseous Release Path	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-108	3.5.1-042	A
	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-108	3.5.1-042	A
Hatches/Plugs	Direct Flow Shelter and Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A9.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A9.TP-23	3.5.1-064	A
Roofing	Shelter and Protection	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
		Stainless Steel Bolting	Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A9.TP-261	3.5.1-088	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-18 Stack (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Siding	Shelter and Protection	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C

Table 3.5.2-18 Stack (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-19
Station Blackout Structure and Foundations
Summary of Aging Management Evaluation

Table 3.5.2-19 Station Blackout Structure and Foundations

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Aluminum Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B3.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B3.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
		Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Stainless Steel	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B3.T-37a	3.5.1-100	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B3.T-37a	3.5.1-100	A
Concrete: Above-grade exterior (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-24	3.5.1-063	A
Conowingo Hydroelectric Plant (Dam)	Shelter and Protection Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-221	3.5.1-083	C, 1
			Water - Flowing	Loss of Material	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-221	3.5.1-083	C, 1

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Conowingo Hydroelectric Plant (Dam)	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-38	3.5.1-059	A, 1
				Cracking	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.T-34	3.5.1-096	E, 1, 2
				Loss of Material (Spalling, Scaling) and Cracking	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-36	3.5.1-060	A, 1
			Raw Water	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-38	3.5.1-059	A, 1
				Cracking	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.T-34	3.5.1-096	E, 1, 2
				Loss of Material; Loss of Form	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.T-22	3.5.1-058	A, 1
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of Material	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	III.A6.T-20	3.5.1-056	A, 1
Duct Banks	Shelter and Protection	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Duct Banks	Shelter and Protection	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Equipment supports and foundations	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
		Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-24	3.5.1-063	A
Manholes, Handholes & Duct Banks	Shelter and Protection Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Manholes, Handholes & Duct Banks	Shelter and Protection Structural Support	Ductile Iron	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Metal components	Structural Support	Aluminum	Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B3.T-37a	3.5.1-100	A
		Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A
Structural Miscellaneous - Decking (Roof)	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Decking (Roof)	Shelter and Protection Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Siding	Shelter and Protection Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-19 Station Blackout Structure and Foundations (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The FERC Inspections of the Conowingo Hydroelectric Plant (Dam) are the aging management program for the Conowingo Hydroelectric Plant (Dam). The Conowingo Hydroelectric Plant (Dam) is located on the Susquehanna River approximately ten miles above the mouth of the river on the Chesapeake Bay, five miles below the Pennsylvania border, and approximately ten miles south of PBAPS. Conowingo is owned and operated by Exelon Generation. Conowingo is part of the PBAPS SBO electrical system. Conowingo is licensed by the Federal Energy Regulatory Commission (FERC). Screening of Conowingo was performed at the plant (dam) level. Screening and aging management review of the plant (dam) were performed for the second period of extended operation based on current licensing basis established for Peach Bottom in NUREG-1769, Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3, Section 3.6.3 “Station Blackout System”. The staff concluded as stated in paragraph 3.6.3.2.1 “Aging Management Program”, “By virtue of the FERC’s authority and responsibility for ensuring that its regulated projects are constructed, operated, and maintained to protect life, health, and property, the staff finds that for earthen embankments, dams, appurtenances, and related structures subject to AMR, continued compliance with FERC requirements during the license renewal period will constitute an acceptable dam aging management program for the purposes of license renewal. Therefore, the staff finds the program acceptable.” PBAPS will continue to comply with these FERC requirements during the second period of extended operation.

2. The FERC Inspections of the Conowingo Hydroelectric Plant (Dam) are substituted to manage aging effect(s) applicable to this component type, material, and environment combination.

Table 3.5.2-20
Turbine Building and Main Control Room Complex
Summary of Aging Management Evaluation

Table 3.5.2-20 Turbine Building and Main Control Room Complex

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Anchors	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (accessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Flood Barrier Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
				Loss of Material	Structures Monitoring (B.2.1.34)	III.A6.T-20	3.5.1-056	E, 1
Concrete: Below-grade exterior (inaccessible areas)	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	HELB/MELB Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Interior (accessible areas)	Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	HELB/MELB Shielding	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
	Missile Barrier Shelter and Protection Shielding Structural Pressure Barrier Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Hatches/Plugs	Shelter and Protection Shielding Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatches/Plugs	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Masonry walls: Interior	Shelter and Protection Shielding Structural Support	Concrete Block	Air - Indoor Uncontrolled	Cracking	Masonry Walls (B.2.1.33)	III.A3.T-12	3.5.1-070	A
Metal components	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Precast Concrete-Beams and Panels	Shelter and Protection Shielding Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
			Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Sliding surfaces	Structural Support	Lubrite	Air - Indoor Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.34)	III.B2.TP-46	3.5.1-074	A
Steel components: structural steel	Structural Support	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	A
Structural Miscellaneous - Decking	Shelter and Protection Structural Support	Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Miscellaneous - Decking	Shelter and Protection Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
Structural Miscellaneous - Missile Barrier	Missile Barrier	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Structural Miscellaneous - Shielding	Shielding	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Structural Miscellaneous - Siding	Shelter and Protection	Carbon Steel	Air - Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
		Galvanized Steel	Air - Indoor Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	C
		Stainless Steel Bolting	Air - Indoor Uncontrolled	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
			Air - Outdoor	Cracking	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Material	One-Time Inspection (B.2.1.21)	III.B2.T-37a	3.5.1-100	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-20 Turbine Building and Main Control Room Complex (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. The Structures Monitoring (B.2.1.34) program is substituted to manage the aging effects applicable to this component type, material, and environment combination, for the circulating water discharge tunnel.

Table 3.5.2-21
Watertight Dikes
Summary of Aging Management Evaluation

Table 3.5.2-21 Watertight Dikes

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Above-grade exterior (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Below-grade exterior (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-21 Watertight Dikes (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

Table 3.5.2-22
Yard Structures (Manholes, Duct Banks, Valve Pits, etc.)
Summary of Aging Management Evaluation

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Structural)	Structural Support	Galvanized Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: All (Foundation Condensate Storage Tanks)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
Concrete elements: All (Foundation Diesel Storage Tanks)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete elements: All (Foundation Diesel Storage Tanks)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
Concrete elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-274	3.5.1-082	A
				Loss of Preload	Structures Monitoring (B.2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements: Curbs	Direct Flow	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete elements: Embedments	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.A3.TP-302	3.5.1-077	C
Concrete: Above-grade exterior (accessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
Concrete: Above-grade exterior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Basemat, Foundation, Subfoundation (accessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation, Subfoundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
Concrete: Below-grade exterior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: Below-grade exterior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	A
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Concrete: Interior (accessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
Concrete: Interior (inaccessible areas)	Missile Barrier Shelter and Protection Structural Support	Reinforced concrete	Air - Indoor Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	C
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
Manholes, Handholes & Duct Banks	Shelter and Protection Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-26	3.5.1-066	A
				Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-25	3.5.1-054	A
				Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-23	3.5.1-064	A
			Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.34)	III.A3.TP-30	3.5.1-044	A
				Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-212	3.5.1-065	A

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Manholes, Handholes & Duct Banks	Shelter and Protection Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.34)	III.A3.TP-204	3.5.1-043	A
				Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.34)	III.A3.TP-29	3.5.1-067	C
			Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.34)	III.A3.TP-67	3.5.1-047	A
Steel components: structural steel	Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.34)	III.B2.TP-6	3.5.1-093	A

Table 3.5.2-22 Yard Structures (Manholes, Duct Banks, Valve Pits, etc.) (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

None.

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 INTRODUCTION

This section provides the results of the aging management review for those components and commodities identified in Section 2.5, Scoping and Screening Results: Electrical, as being subject to aging management review. The components or commodities, which are addressed in this section are described in the indicated sections.

- Cable Connections (Metallic Parts) (2.5.2.5.1)
- Electrical Insulation for Electrical Cables and Connections (2.5.2.5.2)
  - Electrical Insulation for Electrical Cables and Connections
    - Includes:
      - Electrical Penetration Pigtails
      - Splices
      - Insulating Portions of Terminal Blocks
      - Insulating Portions of Fuse Holders (not part of active equipment).
  - Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
  - Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
  - Electrical Conductor Insulation for Inaccessible Low Voltage Power Cables
  - Electrical Conductor Insulation for Inaccessible Medium Voltage Power Cables
- Electrical Penetrations (2.5.2.5.3)
- Fuse Holders (not part of active equipment) (2.5.2.5.4)
- High Voltage Electrical Insulators (2.5.2.5.5)
- Metal Enclosed Bus (2.5.2.5.6)
- Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors (2.5.2.5.7)
- Wooden Pole (2.5.2.5.8)

The electrical commodity groups which are addressed in this section are described in the indicated sections. Electrical Penetrations are not subject to their own aging management review in this section in that they are addressed 1) as a TLAA in the Environmental Qualification of Electric Equipment (B.3.1.3) program and 2) in the containment structure aging management review.

3.6.2 RESULTS

The following tables summarize the results of the aging management review for electrical components and commodities.

Table 3.6.2-1 - Summary of Aging Management Evaluation For Electrical Commodities

3.6.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.6.2.1.1 Cable Connections (Metallic Parts)

Materials

The materials of construction for the Cable Connections (Metallic Parts) are:

- Various Metals Used for Electrical Contacts

Environments

The Cable Connections (Metallic Parts) are exposed to the following environments:

- Air – Indoor, Controlled
- Air – Indoor, Uncontrolled
- Air - Outdoor

Aging Effect Requiring Management

The following aging effect associated with the Cable Connections (Metallic Parts) requires management:

- Increased Electrical Resistance of Connection

Aging Management Program

The following aging management program manages the aging effects for the Cable Connections (Metallic Parts):

- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)

3.6.2.1.2 Electrical Insulation for Electrical Cables and Connections

The electrical insulation for electrical cables and connections commodity group was broken down for aging management review of insulation into subcategories based on categorization in NUREG-2191:

- Electrical Insulation for Electrical Cables and Connections
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits

- Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Conductor Insulation for Inaccessible Low Voltage Power Cables
- Electrical Conductor Insulation for Inaccessible Medium Voltage Power Cables

This insulation material commodity group includes insulated cables and connections, electrical penetration pigtails, splices, insulating portions of terminal blocks, and insulating portions of fuse holders (not part of active equipment).

Materials

The materials of construction for the Electrical Insulation for Electrical Cables and Connections are:

- Various Organic Polymers

Environments

The Electrical Insulation for Electrical Cables and Connections are exposed to the following environments:

- Adverse Localized Environment
- Adverse Localized Environment caused by Significant Moisture

Aging Effects Requiring Management

The following aging effects associated with the Electrical Insulation for Electrical Cables and Connections require management:

- Reduced Electrical Insulation Resistance
- Reduced Electrical Insulation Resistance or Degraded Dielectric Strength

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical Insulation for Electrical Cables and Connections:

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.37)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.41)

- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39)

3.6.2.1.3 Fuse Holders (not part of active equipment): Metallic Clamps

Materials

The materials of construction for the Fuse Holders (not part of active equipment): Metallic Clamps are:

- Various Metals Used for Electrical Connections

Environments

The Fuse Holders (not part of active equipment): Metallic Clamps are exposed to the following environments:

- Air – Indoor, Controlled
- Air – Indoor, Uncontrolled

Aging Effect Requiring Management

The Fuse Holders (not part of active equipment): Metallic Clamps have no aging effects requiring management. See subsection 3.6.2.3.1.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Fuse Holders (not part of active equipment): Metallic Clamps.

3.6.2.1.4 High Voltage Electrical Insulators

Materials

The materials of construction for the High Voltage Electrical Insulators are:

- Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement

Environment

The High Voltage Electrical Insulators are exposed to the following environment:

- Air – Outdoor

Aging Effects Requiring Management

The High Voltage Electrical Insulators have no aging effects requiring management. See subsection 3.6.2.3.2.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the High Voltage Electrical Insulators.

3.6.2.1.5 Metal Enclosed Bus

Materials

The materials of construction for the Metal Enclosed Bus; Bus/Connections; Electrical Insulation, Electrical Insulators; and External Surface of Enclosure Assemblies are:

- Various Metals Used for Electrical Bus and Connections
- Porcelain, Various Organic Polymers
- Galvanized Steel; Aluminum

Environments

The Metal Enclosed Bus are exposed to the following environments:

- Air – Indoor, Controlled
- Air – Indoor, Uncontrolled
- Air – Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Metal Enclosed Bus require management:

- Increased Electrical Resistance of Connection
- Reduced Electrical Insulation Resistance
- Loss of Material

Aging Management Program

The following aging management program manages the aging effects for the Metal Enclosed Bus:

- Metal Enclosed Bus (B.2.1.42)

3.6.2.1.6 Switchyard Bus and Connections

Materials

The materials of construction for the Switchyard Bus and Connections are:

- Aluminum, Copper, Bronze, Stainless Steel, Galvanized Steel

Environment

The Switchyard Bus and Connections are exposed to the following environment:

- Air – Outdoor

Aging Effects Requiring Management

The Switchyard Bus and Connections have no aging effects requiring management. See Subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Switchyard Bus and Connections.

3.6.2.1.7 Transmission Conductors

Materials

The materials of construction for the Transmission Conductors:

- Aluminum
- Aluminum, Steel

Environment

The Transmission Conductors are exposed to the following environment:

- Air – Outdoor

Aging Effects Requiring Management

The Transmission Conductors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Conductors.

3.6.2.1.8 Transmission Connectors

Materials

The materials of construction for the Transmission Connectors are:

- Aluminum, Steel

Environment

The Transmission Connectors are exposed to the following environment:

- Air – Outdoor

Aging Effects Requiring Management

The Transmission Connectors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Connectors.

3.6.2.1.9 Wooden Pole

Materials

The material of construction for the Wooden Pole is:

- Treated Wood

Environments

The Wooden Pole is exposed to the following environments:

- Air – Outdoor
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Wooden Pole require management:

- Loss of Material; Change in Material properties

Aging Management Program

The following aging management program manages the aging effects for the Wooden Pole:

- Wooden Pole (B.2.2.1)

3.6.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the electrical commodities, those programs are addressed in the following subsections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-LR.

Table 3.6.1 Item Number 3.6.1-001: The evaluation of this TLAA is addressed in Section 4.4, "Environmental Qualification of Electric Equipment," of this application.

3.6.2.2.2 Reduced Insulation Resistance Due to Age Degradation of Cable Bus Arrangements Caused by Intrusion of Moisture, Dust, Industrial Pollution, Rain, Ice, Photolysis, Ohmic Heating and Loss of Strength of Support Structures and Louvers of Cable Bus Arrangements Due to General Corrosion and Exposure to Air Outdoor

Reduced insulation resistance due to age degradation of cable bus caused by intrusion of moisture, dust, industrial pollution, rain, ice, photolysis (for ultraviolet sensitive material only), ohmic heating and loss of strength of support structures, covers or louvers of cable bus arrangements due to general corrosion or exposure to air outdoor could occur in cable bus assemblies. Cable bus is a variation of metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, and ice and therefore may introduce debris into the internal cable bus assembly.

Consequently, cable bus construction and arrangements are such that it may not readily fall under a specific GALL-SLR Report AMP (e.g., GALL-SLR Report AMP XI.E1 and AMP XI.E4). GALL-SLR Report AMP XI.E1 calls for a visual inspection of accessible insulated cables and connections subject to an adverse localized environment which may not be applicable to cable bus due to inaccessibility or applicability of the aging mechanisms and effects. GALL-SLR Report AMP XI.E4 includes tests and inspections of the internal and external portions of the MEB. The MEB internal and external inspections and tests may not be applicable to cable bus aging mechanisms and effects. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant-specific further evaluation. The evaluation includes associated AMPs: AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," and AMP XI.S6, "Structures Monitoring." Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.6.1 Item Numbers 3.6.1-029, 3.6.1-030; 3.6.1-031, and 3.6.1-032: There are no Cable Bus: electrical insulation; insulators or Cable Bus: external surface of enclosure assemblies in Electrical Commodities because there is no cable bus, in the scope of license renewal, at PBAPS.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL-SLR Report recommends further evaluation of a plant-specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.6.1:

- Item Number 3.6.1-004 - ACSR Transmission Conductors

- Item Number 3.6.1-005 - Transmission Connectors
- Item Number 3.6.1-006 – Switchyard Bus and Connections
- Item Number 3.6.1-007 – Aluminum and ACSR Transmission Conductors.
- Item Number 3.6.1-021 – Aluminum Transmission Conductors

The transmission conductors, transmission connectors, and switchyard bus and connections evaluated for PBAPS are those that are part of the circuits which supply power from electric utility transmission system to plant buses, including connecting the alternate ac source in the event of a station black out. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout event and during post fire safe shutdown, when offsite power is credited.

The in scope commodities in the circuits for offsite power sources and the station blackout alternate ac source include 500 kV, 220 kV, 34 kV, and 13 kV switchyard bus and connections; 13 kV aluminum conductor, steel reinforced (ACSR) transmission conductor in the second offsite source that is routed between the two transitions from underground to aerial circuits and transmission connectors; 34 kV station blackout AAC aluminum transmission conductor; and transmission connectors.

Wind-Induced Abrasion and Fatigue – Transmission Conductors

Table 3.6.1 - Item Number 3.6.1-007 – ACSR and Aluminum Transmission Conductors: Transmission conductor vibration or sway could be caused by wind loading. Industry experience has shown that the transmission conductors do not normally swing significantly. When transmission conductors do swing due to a substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission line to vibrate or sway is considered in design and installation. Therefore, the loss of material aging effect that could result from wind-induced transmission conductor vibration or sway is not applicable and would not cause a loss of intended function for transmission conductors for the second period of extended operation.

Corrosion – Transmission Conductors

Table 3.6.1 - Item Number 3.6.1-004 - ACSR Transmission Conductors and Item Number 3.6.1-021 - Aluminum Transmission Conductors: PBAPS has two transmission conductor circuits. The first circuit is three 34 kV 556 kcmil aluminum transmission conductors routed between the Susquehanna Substation and the adjacent wooden pole where the circuit transitions from the substation to overhead transmission conductors to underground cable. This short transmission conductor span (about 30 feet) is part of the station blackout alternate ac circuit. The second circuit is three 13 kV 1590 kcmil aluminum conductor steel reinforced (ACSR) transmission conductors routed between the two underground cable to aerial conductor transitions in the circuit for the second offsite source. This circuit traverses the cliff on the west side of the PBAPS site between the plant and the North Substation.

The first circuit has a short span of three 34 kV 556 kcmil aluminum transmission conductors. Because these conductors are aluminum they are not subject to the aging effect of loss of conductor strength due to corrosion. Therefore, the aluminum transmission conductors between the Susquehanna Substation and the adjacent wooden pole do not require aging management.

The second circuit has three transmission conductors that are 1590 MCM 54/19 aluminum conductor steel reinforced (ACSR). Each phase has one conductor. This circuit was installed in 1993. The 1590 MCM 54/19 ACSR transmission conductor is a large, substantial transmission conductor. It is approximately 1.5 inches in diameter and is configured with 19 steel conductors wrapped by 54 aluminum conductors. The ultimate strength per American Society for Testing and Materials (ASTM) standards for 1590 kcmil ACSR is 54500 lbs, and the heavy load tension design limit for this 1590 kcmil circuit at PBAPS is 12500 lbs.

The PECO Transmission and Distribution design practices follow the National Electrical Safety Code (NESC) methodologies. The NESC requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension of a conductor must be designed to withstand heavy load requirements, which include consideration of ice, wind, and temperature.

The most prevalent contribution to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality which includes suspended particles chemistry, sulfur dioxide (SO_2) concentration in air, precipitation, fog chemistry, and meteorological conditions.

Ontario Hydroelectric performed a study that is documented in 1992 IEEE Transactions on Power Delivery. The papers present the methodology and results of both field and laboratory tests on ACSR conductors from Ontario Hydroelectric’s older transmission lines. The field tests were performed on-line, to detect steel core galvanizing loss by using an overhead line conductor corrosion detector. Potential conductor degradation is measured by an eddy current sensor that travels along the conductor, between transmission towers. Laboratory tests were performed for fatigue, tensile strength, torsional ductility, and electrical performance. The fatigue tests simulating 50 years of service life were performed to assess existing cables as well as a new cable. The tensile strength was assessed by the individual wire method, and torsional ductility was assessed by the twist to failure method. Both the tensile strength and torsional ductility tests were performed in accordance with published standards. Additional considerations in the performance of these aging assessments included metallurgical data and analysis for potential environmental contributors. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The PBAPS in scope transmission conductors are the same type of transmission conductors evaluated in the Ontario Hydroelectric study and in the EPRI License Renewal Electrical Handbook. The test methodology as published in the IEEE Transactions on Power Delivery is applicable to in scope PBAPS ACSR transmission conductors.

PBAPS is located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry nearby. In the Ontario Hydroelectric Study, the conductors most affected by atmospheric corrosion were located in areas subject to pollution sources and a major urban area. Therefore, the environmental impact to the PBAPS transmission conductors (which are located in a rural area) are bounded by the Ontario Hydroelectric conductors (which were located in polluted and urban environments).

An example presented in the EPRI License Renewal Handbook, 3002010401, compares a 4/0 conductor to the results of the Ontario Hydroelectric Study. The EPRI License Renewal Electrical Handbook evaluation documents that a 4/0 ACSR conductor (equivalent to a 211 MCM conductor size), which was included in the Ontario Hydroelectric study, has the smallest ultimate strength margin. Larger, more substantial transmission conductors (e.g., 336.4 MCM 30/7 conductors) that had a greater strength margin were bounded by the 4/0, 6/1 ACSR conductor example. The PBAPS transmission conductors are physically more substantial than the limiting 4/0 ACSR conductor. NESC requirements and the handbook guidance are used to evaluate the in scope ACSR transmission conductors at PBAPS.

Assuming a 30 percent loss of strength as demonstrated by the Ontario Hydroelectric tests, there would still be significant margin between what is required by the NESC and actual conductor strength. The margin between the NESC heavy load and the ultimate strength is 42000 lbs.; there is a 77 percent ultimate strength margin. The Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80 year old conductor. In the case of the 1590 kcmil 54/19 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be 38150 lbs, i.e., 47 percent, margin between the 80-year old ultimate strength and the strength required by the NESC. Comparing both the ultimate strength adjusted for 80 years of aging (38150 lbs.) and the PBAPS heavy load tension design limit applicable to the conductors (12500 lbs.), to the NESC 60 percent design strength tension limit (32700 lbs.), demonstrates margin for the PBAPS ACSR transmission conductors as they age. The design and physical construction of the PBAPS in scope transmission conductors during the second period of extended operation is bounded by the handbook analysis of the 4/0 ACSR conductor and is also bounded by the Ontario Hydroelectric study.

1590 MCM 54/19 ACSR Transmission Conductor	
Ultimate Strength, New	54500 lbs
Postulated Ultimate Strength at 80 Years	38150 lbs
NESC Design Strength, Required, New	32700 lbs
NESC Heavy Load Tension, PBAPS Design Limit	12500 lbs.

In conclusion, the in scope PBAPS transmission conductors are bounded by the Ontario Hydroelectric study by test methodology, design and construction, and environment. The above evaluations demonstrate with reasonable assurance that transmission conductors will have ample strength margin through the second period of extended operation. Therefore, based on PBAPS design and confirmed by their operating experience, the loss of transmission conductor strength does not require aging management activities for the second period of extended operation.

Oxidation or Loss of Pre-Load – Transmission Connectors

Table 3.6.1 - Item Number 3.6.1-005 - Transmission Connectors: Transmission connectors employ good bolting practices. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of pre-load. The transmission connectors are designed and installed using stainless steel lock washers that provide vibration absorption and prevent loss of preload. Therefore, based on PBAPS design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for PBAPS transmission connectors.

Wind-Induced Abrasion and Fatigue – Switchyard Bus

Table 3.6.1 - Item Number 3.6.1-006 – Switchyard Bus and Connections: PBAPS is located inland, in south central Pennsylvania. Switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components, such as concrete footings and structural steel. Switchyard bus is rigidly mounted and is therefore not subject to abrasion induced by wind loading. Therefore, based on PBAPS design and confirmed by operating experience, wind-induced abrasion and fatigue are not applicable aging mechanisms for PBAPS switchyard bus.

Oxidation or Loss of Pre-Load – Switchyard Bus Connections

Table 3.6.1 - Item Number 3.6.1-006 – Switchyard Bus and Connections: Switchyard bus connections employ good bolting practices. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of pre-load. The switchyard bus bolted connections are designed and installed using stainless steel lock washers that provide vibration absorption and prevent loss of preload. Therefore, based on PBAPS design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for PBAPS switchyard bus connections.

Conclusion

Aging management activities for PBAPS switchyard bus and connections, transmission conductors, and transmission connectors are not required for the second period of extended operation.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Second License Renewal are discussed in Section B.1.3.

3.6.2.2.5 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, section B.1.4.

3.6.2.3 AMR Results Not Consistent With or Not Addressed in the GALL-SLR Report

3.6.2.3.1 Fuse Holders

Table 3.6.1 Item Numbers 3.6.1-016, 3.6.1-017, and 3.6.1-018 – Fuse Holders (not part of active equipment) Metallic Clamps: Potential aging effects for the metallic clamps of fuse holders, not part of active equipment were evaluated to determine if the GALL-SLR report XI.E5, "Fuse Holders" aging management program was to be implemented for PBAPS second license renewal.

Fuse holders are in scope for license renewal at PBAPS by meeting (a)(1), (a)(2) functional, or (a)(3) license renewal 10 CFR 54.4 scoping criteria. In accordance with the bounding approach described in NEI 17-01, the fuse holders are an electrical commodity group and are assessed for aging management review by applying the criteria of 10 CFR 54.21(a)(1)(i). The resulting fuse holder population evaluated for aging effects are those that are passive and long lived; i.e., those that are not part of active equipment or assembly. The passive, long lived fuse holders that screen in are evaluated to determine if they are subject to:

- adverse environmental conditions that could cause an increase in electrical resistance of connection,
- fatigue from ohmic heating, thermal cycling, or electrical transients, or
- fatigue from frequent fuse removal/manipulation or vibration.

A systematic review of the fuse holders: metallic clamps was performed for PBAPS, considering the above scoping and screening criteria and aging effects and mechanisms. The list of fuses/fuse holders for consideration was compiled from fuse and fuse holder components identified on controlled drawings, in the plant equipment database, and in other plant design documents. The population of fuse holders for consideration totaled over 14,000. The systematic review applied the above criteria in parallel. The results of the review identified thirty fuse holders that require aging management review. These fuse holders are located in twenty different enclosed electrical boxes.

<u>DC System</u>

Twenty-six fuse holders found in eighteen different enclosed electrical boxes serve the DC System. The fuse holders are in the battery rooms.

The potential aging effects as discussed in NUREG-2192 are not applicable to these fuse holders. The evaluation of aging effects is discussed below.

- Chemical Contamination, Corrosion, and Oxidation

  The electrical boxes in the PBAPS battery rooms are in an environment that does not subject them to environmental aging mechanisms. They are located inside the power block. The fuse holders are protected from chemical contamination and are within a mild environment inside the power block during normal conditions. There are no sources of uncontrolled chemicals near the electrical boxes during normal conditions. The environment inside the rooms is air-conditioned by a ventilation system; therefore, they do not experience high relative humidity during normal conditions. The fuse holders are not subject to outside weather conditions and therefore, are not subject to moisture from precipitation. A second barrier that protects the fuse holders from exposure to moisture is their location inside an enclosed electrical box. The fuse holders are not located in or near humid areas and they are not exposed to industrial or oceanic environments.

  A walkdown of these electrical boxes containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

- Ohmic Heating, Thermal Cycling, and Electrical Transients

  Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. The loads fed from these panels are control circuits that operate at low currents and standby loads. Control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Standby loads do not experience appreciable thermal cycling or ohmic heating. Therefore, ohmic heating and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

  Mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The corrective action program is used to document adverse conditions and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices. Therefore, electrical transients are not considered an applicable aging mechanism for these fuse holders.

- Frequent Manipulation and Vibration

  Wear and fatigue is caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e. removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

These fuse holders are in electrical boxes that are not mounted on moving or rotating equipment such as compressors, fans, or pumps. Because the electrical boxes are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Substations and Transformers

Four fuse holders found in two different enclosed electrical boxes feed the DC control power circuits in the Substations and Transformer system. The fuse boxes are located, one, in the north 500 kV switchyard control house and two, in the north 220 kV switchyard control house.

The potential aging effects as discussed in NUREG-2192 are not applicable to these fuse holders. The evaluation of aging effects is discussed below.

- Chemical Contamination, Corrosion, and Oxidation

  The electrical boxes in the north substation 500 kV and 220 kV control houses are in an environment that does not subject them to environmental aging mechanisms. They are located inside their respective switchyard control house. The fuse holders are protected from chemical contamination and are within a mild environment inside the switchyard control house during normal conditions. There are no sources of uncontrolled chemicals near the electrical boxes during normal conditions. The environment inside the rooms is controlled by a ventilation system; therefore, they do not experience high relative humidity during normal conditions. The fuse holders are not subject to outside weather conditions and therefore, are not subject to moisture from precipitation. A second barrier that protects the fuse holders from exposure to moisture is their location inside an enclosed electrical box. The fuse holders are not located in or near humid areas, and they are not exposed to industrial or oceanic environments.

  A walkdown of these electrical boxes containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

- Ohmic Heating, Thermal Cycling, and Electrical Transients

  Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. The loads fed from these panels are control circuits that operate at low currents and standby loads. Control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Standby loads do not experience appreciable thermal cycling or ohmic heating. Therefore, ohmic heating and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The corrective action program is used to document adverse conditions and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices. Therefore, electrical transients are not considered an applicable aging mechanism for these fuse holders.

- Frequent Manipulation and Vibration

  Wear and fatigue is caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e. removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

  These fuse holders are in electrical boxes that are not mounted on moving or rotating equipment such as compressors, fans, or pumps. Because the electrical boxes are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Summary of Aging Management Review Results

There are thirty fuse holders in scope for license renewal that are not part of active equipment at Peach Bottom that are subject to aging management review. Based on installed location, design configuration, operating service conditions, and operating experience, the thirty fuse holders inside the twenty electrical boxes located in the PBAPS power block and north substation 500 kV and 220 kV control houses are not susceptible to the aging effects and mechanisms associated with metallic clamps. Therefore, aging management activities are not required for these thirty fuse holders (not part of active equipment): metallic clamps at PBAPS.

PBAPS fuse holders (not part of active equipment): insulation material that may be subject to an adverse localized environment that may affect insulation resistance are addressed as part of Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. Fuse holder insulation material that is not subject to an adverse environment does not have aging effects requiring management.

Conclusion

Aging management activities for PBAPS fuse holders (not part of an active equipment): metallic clamps are not required for the second period of extended operation; therefore, the GALL-SLR report XI.E5 “Fuse Holders” aging management program is not applicable to PBAPS for the second period of extended operation.

3.6.2.3.2 High-Voltage Electrical Insulators

Table 3.6.1 Item Numbers 3.6.1-002 and 3.6.1-003 – High-Voltage Electrical Insulators:

The PBAPS in scope high voltage electrical insulators (HVIs) were evaluated for aging effects requiring management during aging management reviews. The HVIs in scope for license renewal are located in the offsite power source circuits and the alternate AC source for the SBO coping period. The in scope insulators include:

- 500 kV and 220 kV post insulators in offsite source paths 2SU, 343SU, and 3SU.

- 34.5 kV post insulators and strain insulators for the Susquehanna Substation and transmission connection conductor to the adjacent wooden pole,

- 13 kV post insulators and strain insulators for the 13 kV portion of offsite source paths, 2SU, 343SU, and 3SU.

The in scope HVIs provide electrical insulation for switchyard bus, transmission conductors, switchyard active components, and associated connections that are part of the circuits that supply power from electric utility transmission system to plant buses, including connecting the alternate AC source in the event of a station black out. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout event and during post fire safe shutdown, when offsite power is credited.

<u>Airborne Contamination</u>

Various airborne materials such as salt, dust, fog, cooling tower plume, foreign debris, or industrial effluents can contaminate insulator surfaces. An excessive buildup of surface contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. The buildup of surface contamination is gradual and in most areas, such contamination is washed away by rain, where the glazed insulator surface aids in contamination removal.

Excessive surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near the seacoast where salt spray is prevalent, dust, near industrial facilities that discharge airborne pollutants, or at sites where the cooling tower plume may deposit contaminants on switchyard components and transmission lines.

At PBAPS and Susquehanna Substation, the in scope HVIs; the 500 kV, 220 kV, 34.5 kV, and 13 kV post insulators and the 34.5 kV and 13 kV strain insulators, were evaluated for susceptibility to airborne surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents. PBAPS and Susquehanna Substation are not located in an environment conducive to accelerated aging. Considering potential airborne salt contamination, the HVIs are not located near a seacoast or near a brackish waterway. PBAPS and Susquehanna Substation are approximately 10 miles away from the nearest seacoast or brackish waterway (Chesapeake Bay). It is located inland, in south central Pennsylvania where there is no source of airborne salt contamination. Considering potential airborne particulate contamination from industrial and agricultural activities (i.e., dust, soot), the HVIs are located in an area where industrial airborne particle concentrations and agricultural airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry or agricultural pollution nearby. The nearest industrial facility is a clean air, natural gas fired power plant located approximately 2.5 miles away. Considering potential cooling tower plume contamination, the cooling towers at PBAPS are mechanical cooling towers located along the river, at the south end of the site. In scope HVIs are located upriver, at the north end of the site, in transmission substations atop the cliff adjacent to the plant site, and at the Susquehanna Substation and adjacent wooden pole which are approximately 10 miles downriver. The plume from these cooling towers poses no contamination risk to the in scope HVIs because the mechanical cooling towers that are approximately 50 feet in height and are greater than a quarter mile away from the nearest in scope HVIs. These plumes quickly dissipate before reaching the nearest in scope HVIs. Considering potential foreign debris, the HVIs are located in rural area with no heavy industry or urban population centers. The nearest residential community is 3 miles away from PBAPS and 1 mile away from the Susquehanna Substation.

Fog, in and of itself, is not a contaminant for HVIs. Therefore, surface contamination from fog is not an aging effect, is not subject to an aging management review, and does not require aging management.

A ten-year search of operating experience for HVIs was performed. Cumulative build up HVI contamination has not been experienced at PBAPS. Additionally, there are no existing preventive maintenance or inspection tasks that are precluding an occurrence of excessive HVI surface contamination.

Based on PBAPS and the Susquehanna Substation locations, lack of substantial airborne contaminants, and its corroborating operating experience, excessive HVI surface contamination is not expected to occur. HVI surface contamination is not a significant aging effect for PBAPS as noted by recent visual observations of these HVIs in preparation of this application. Therefore, aging effects of surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents are not applicable to PBAPS for the second period of extended operation. No aging management activity is required for the HVIs due to airborne contamination.

In addition, an evaluation was performed for cracking of porcelain. Porcelain cracking or breaking is most commonly caused by an object striking the HVI. Porcelain cracking has also occurred when cement that binds the parts together expands excessively. This phenomenon is known as cement growth; it occurs as a result of improper manufacturing that makes the cement more susceptible to moisture penetration. Plant specific OE shows that porcelain cracking due to cement growth has not occurred at PBAPS. Therefore, cracking caused by physical damage is not an aging effect, is not subject to an aging management review, and does not require aging management.

<u>Loss of Material - Mechanical Wear or Corrosion</u>

Loss of material of HVIs can occur due to oscillating movement of transmission conductors due to significant and sustained winds. Significant wind can result in mechanical wear of metallic parts. Surface corrosion of HVI metallic parts can also occur due to environmental contamination or if galvanized or other protective coatings are worn from significant wind induced movement of transmission conductors.

Mechanical wear is an aging effect for strain insulators in that they are subject to movement. Movement can be caused by wind blowing the supported transmission conductor, causing it to swing. If this swinging is frequent enough, it could cause wear in the metal contact points of the insulator string.

The HVIs to be evaluated for aging effects due to movement of transmission conductors due to significant wind are those conductors with strain HVIs, which for PBAPS and the Susquehanna Substation, only include medium voltage transmission conductors. The in scope strain insulators are for the 34.5 kV transmission connection conductor routed between the Susquehanna Substation and the wooden pole adjacent to the substation and for the 13 kV transmission conductor that traverses the cliff to the west of PBAPS for the 343 startup feed. The 34.5 kV transmission conductors are a connection span of three 34.5 kV 556 kcmil aluminum conductors, approximately 30 feet in length. The 13 kV transmission conductors have a relatively short, two spans of three 13 kV 1590 MCM 54/19 ACSR conductors with lengths of 760 feet and 410 feet. The PECO Transmission and Distribution design practices follow the National Electrical Safety Code (NESC) methodologies. The NESC sets the maximum tension of a conductor to withstand heavy load requirements which includes consideration of oscillating movement of transmission conductors due to significant wind.

Although this loss of material due to mechanical wear or corrosion of the metallic parts of HVIs is possible, experience has shown that the transmission conductors do not normally swing and that when they do, due to significant wind, they do not continue to swing for very long once the wind has subsided. Wind loading, that can cause a transmission line to sway, is considered and minimized during design and installation. In additional, the concerns for transmission conductor to swing is reduced for shorter spans.

In addition, the installed configuration of the strain insulators minimizes movement. This reduces mechanical wear of metallic parts within the strain insulators such that these metallic contact points do not require inspection for mechanical wear. Therefore, aging effects due to loss of material due to mechanical wear is not applicable to PBAPS for the second period of extended operation.

Loss of material due to corrosion of HVIs can also occur due to airborne contamination. A large buildup of contamination could result in corrosion of the metallic parts of the HVIs, which if significant, could impact its structural intended function. As previously evaluated, based on the HVIs' location, lack of airborne contaminants, and its corroborating operating experience, HVI metallic parts are not subject to a large buildup of contamination from airborne contaminants. Therefore, these metallic contact points do not require inspection for corrosion.

HVI metallic part contamination induced corrosion is not a significant aging effect for PBAPS. Therefore, aging effects of surface contamination induced metallic parts corrosion are not applicable to PBAPS for the second period of extended operation.

HVI metallic part aging due to wear from transmission conductor movement, airborne contamination, and surface rust are not significant aging concerns at PBAPS. These conditions have been addressed in design specifications. Visual observations have not identified significant corrosion during routine switchyard inspections, and are further confirmed as not occurring, per a review of operating experience which did not identify these aging effects as the cause or failure mechanism of documented issues with HVIs. These aging effects are not significant at PBAPS and will not impact intended function of the HVIs during the second period of extended operation. Therefore, aging effects of loss of material due to mechanical wear or corrosion are not applicable to PBAPS for the second period of extended operation.

Conclusion

Aging management activities for PBAPS high voltage insulators are not required for the second period of extended operation; therefore, the GALL-SLR report XI.E7 “High Voltage Insulators” aging management program is not applicable to PBAPS.

In addition, to support this conclusion, in accordance with NUREG-2192 requirements, the SSC’s including the HVI required to cope with, and recover from, the SBO event are included within the scope of second license renewal. These second license renewal boundaries include components credited to cope with, and recover from, the SBO event were established based on PBAPS current licensing basis consistent with the first license renewal application and aligned with the second license renewal scoping methodology. The HVIs are included in the scope of second license renewal. In NUREG-1769, Safety Evaluation Report (SER) related to license renewal of PBAPS, Section 2.5.1. SER Section 2.5.3 concludes there is reasonable assurance that the applicant has adequately identified the electrical and instrumentation and control SSC’s that were within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21 (a)(1). These HVI’s are documented as an electrical commodity that the AMR determined the aging effect to be none and, therefore, no aging management activity is required for the HVIs. The evaluations for the first period of extended operation concluded that the HVIs did not require aging management activities to continue to perform their intended function during the first period of extended operation. In agreement with the evaluations performed for the first period of extended operation, airborne contamination and loss of material due to mechanical wear or corrosion are not aging effects requiring management in that they would not cause a loss of intended function if left unmanaged for the second period of extended operation.

3.6.2.4 Time-Limited Aging Analysis

The time-limited aging analysis identified below is associated with Electrical Commodities:

Section 4.4, Environmental Qualification of Electric Equipment.

3.6.3 CONCLUSION

The electrical commodities that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the electrical commodities are identified in the summaries in Section 3.6.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the second period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the electrical commodities will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the second period of extended operation.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-001	Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of various polymeric and metallic materials in plant areas subject to a harsh environment (i.e., loss of coolant accident (LOCA), high energy line break (HELB), or post LOCA environment or, An adverse localized environment for the most limiting qualified condition for temperature, radiation, or moisture for the component material (e.g., cable or connection insulation).	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	EQ is a time-limited aging analysis (TLAA) to be evaluated for the subsequent period of extended operation. See the Standard Review Plan, Section 4.4, "Environmental Qualification (EQ) of Electric Equipment," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See AMP X.E1, "Environmental Qualification (EQ) of Electric Equipment," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes	Environmental Qualification is a TLAA; further evaluation is documented in subsection 3.6.2.2.1.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, "High-Voltage Insulators"	No	Not Applicable. Based on PBAPS design and operating experience, loss of material is not an applicable aging effect for high voltage electrical insulators in Electrical Commodities. In scope high voltage insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air - outdoor environment are not subject to loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind. See subsection 3.6.2.3.2

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-003	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination	AMP XI.E7, "High-Voltage Insulators"	No	Not Applicable. Based on PBAPS geographic location, design, and operating experience, reduced insulation resistance is not an applicable aging effect for high voltage electrical insulators in Electrical Commodities. In scope high voltage electrical insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air - outdoor environment are not subject to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume, or industrial effluent contamination. See subsection 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	Not Applicable. See subsection 3.6.2.2.3.
3.6.1-005	Transmission connectors composed of aluminum; steel exposed to air – outdoor	Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes	Not Applicable. See subsection 3.6.2.2.3.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Not Applicable. See subsection 3.6.2.2.3.
3.6.1-007	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for All Aluminum Conductor (AAC), ACAR and ACSR	Yes	Not Applicable. See subsection 3.6.2.2.3.
3.6.1-008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.37) program will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections exposed to adverse localized environments.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.38) program will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections used in instrumentation circuits exposed to adverse localized environments.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield exposed to an adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength due to significant moisture	AMP XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," AMP XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," or AMP XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191 with exceptions. The Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39), Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40), and Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.41) programs will be used to manage reduced electrical insulation resistance or degraded dielectric strength of the various organic polymers in electrical conductor insulation for inaccessible medium voltage (2 kV to 35 kV) power, instrumentation and control, and low voltage (typically < 1 kV but no greater than 2 kV) cables exposed to adverse localized environments caused by significant moisture.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-011	Metal enclosed bus: enclosure assemblies composed of elastomers exposed to air – indoor controlled or uncontrolled, air – outdoor	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening or loss of strength due to elastomer degradation	AMP XI.E4, "Metal Enclosed Bus," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no metal enclosed bus enclosure assemblies composed of elastomers, exposed to air - indoor, controlled; air – indoor, uncontrolled; or air - outdoor.
3.6.1-012	Metal enclosed bus: bus/connections composed of various metals used for electrical bus and connections exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to the loosening of bolts caused by thermal cycling and ohmic heating	AMP XI.E4, "Metal Enclosed Bus"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.1.42) program will be used to manage increased electrical resistance of connection of the various metals used for electrical bus and connections in metal enclosed bus exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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, air – outdoor	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics/ thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	AMP XI.E4, "Metal Enclosed Bus"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.1.42) program will be used to manage reduced electrical insulation resistance of the porcelain and various organic polymers in metal enclosed bus: electrical Insulation, electrical insulators exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor.
3.6.1-014	Metal enclosed bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.E4, "Metal Enclosed Bus," or AMP XI.S6, "Structures Monitoring"	No	Not Applicable. There are no steel metal enclosed bus, external surfaces of enclosure assemblies, exposed to air-indoor, uncontrolled, air – outdoor environments in Electrical Commodities.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.1.42) program will be used to manage loss of material of the galvanized steel or aluminum metal enclosed bus: external surface of enclosure assemblies exposed to air - outdoor.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Not Applicable. Based on fuse holder locations, environments, and operating experience, increased electrical reduced insulation resistance is not an applicable aging effect for fuse holders in Electrical Commodities. There are no in scope fuse holders (not part of active equipment): metallic clamps, comprised of various metals used for electrical connections in an air-indoor, uncontrolled environment and therefore are not subject to reduced electrical insulation resistance since they are not subject to environmental aging effects due to chemical contamination, corrosion, and oxidation. An evaluation has been performed for in scope fuse holders (not part of active equipment): metallic clamps, in an air – indoor, controlled environment that does not subject them to environmental aging effects due to chemical contamination, corrosion, and oxidation. See subsection 3.6.2.3.1.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, electrical transients.	No	Not Applicable. Based on PBAPS design and operating experience, increased electrical resistance is not an applicable aging effect for fuse holders (not part of active equipment): metallic clamps in Electrical Commodities. An evaluation has been performed for in scope fuse holders (not part of active equipment): metallic clamps comprised of various metals used for electrical connections in an air - indoor, controlled or air - indoor, uncontrolled environment and these fuse holders are not subject to increased electrical resistance due to fatigue from ohmic heating, thermal cycling, or electrical transients. See Subsection 3.6.2.3.1.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration.	No	Not Applicable. Based on PBAPS routine maintenance clearance points and operating experience, increased electrical resistance is not an applicable aging effect for fuse holders (not part of active equipment): metallic clamps in Electrical Commodities. An evaluation was performed for in scope fuse holders (not part of active equipment): metallic clamps comprised of various metals used for electrical connections in an air - indoor, controlled or air - indoor, uncontrolled environment and these fuse holders are not subject to increased electrical resistance due to fatigue caused by frequent fuse removal/manipulation or vibration. See Subsection 3.6.2.3.1.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-019	Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43) program will be used to manage increased electrical resistance of connection of the various metals used for electrical contacts cable connections (metallic parts) exposed to air-indoor, controlled; air - indoor, uncontrolled; or air – outdoor in Electrical Commodities.
3.6.1-020	PWR Only				
3.6.1-021	Transmission conductors composed of aluminum exposed to air – outdoor	Loss of conductor strength due to corrosion	None - for ACAR and All Aluminum Conductor (AAC)	No	Not Applicable. There are no aging effects to be managed for all aluminum transmission conductors exposed to air - outdoor environments in Electrical Commodities.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air – indoor controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	Not Applicable. There are no aging effects to be managed for bakelite; phenolic melamine or ceramic; or molded polycarbonate insulation material in fuse holders (not part of active equipment) exposed to an air - indoor, controlled environment in Electrical Commodities.
3.6.1-023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Not Applicable. There are no aging effects to be managed for galvanized steel or aluminum metal enclosed bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled or air - indoor, uncontrolled environments in Electrical Commodities.
3.6.1-024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Not Applicable. There are no steel metal enclosed bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled environments in Electrical Commodities.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-025	This Item Number is not listed in NUREG-2192.				
3.6.1-026	This Item Number is not listed in NUREG-2192.				
3.6.1-027	Cable bus: external surface of enclosure assemblies. Galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not Applicable. There are no galvanized steel or aluminum cable bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled or air - indoor, uncontrolled, environments in Electrical Commodities.
3.6.1-028	This Item Number is not listed in NUREG-2192.				

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes	Not Applicable. There are no cable bus, electrical insulation and insulators, exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor in Electrical Commodities. See subsection 3.6.2.2.2.
3.6.1-030	Cable bus: external surface of enclosure assemblies composed of steel, exposed to air - indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of steel, exposed to air - indoor, uncontrolled or air - outdoor in Electrical Commodities. See subsection 3.6.2.2.2.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-031	Cable bus external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of galvanized steel or aluminum; exposed to air - outdoor in Electrical Commodities. See subsection 3.6.2.2.2.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of steel exposed to air - indoor, controlled in Electrical Commodities. See subsection 3.6.2.2.2.

Table 3.6.2-1
Electrical Commodities
Summary of Aging Management Evaluation

Table 3.6.2-1 Electrical Commodities

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Cable Connections (Metallic Parts)	Electrical Continuity	Various Metals Used for Electrical Contacts	Air – Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Electrical Resistance of Connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)	VI.A.LP-30	3.6.1-019	A
Electric Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various Metallic Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
			Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
	Insulate (Electrical)	Various Polymeric Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
			Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
Electrical Insulation for Electrical Cables and Connections	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment	Reduced Electrical Insulation Resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.37)	VI.A.LP-33	3.6.1-008	A

Table 3.6.2-1 Electrical Commodities (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Electrical Insulation for Electrical Cables and Connections used in Instrumentation Circuits	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment	Reduced Electrical Insulation Resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.38)	VI.A.LP-34	3.6.1-009	A
Electrical conductor insulation for inaccessible instrumentation and control cables	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)	VI.A.LP-35b	3.6.1-010	B
Electrical conductor insulation for inaccessible low-voltage cables - typical operating voltage of < 1 kV but no greater than 2 kV	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.41)	VI.A.LP-35c	3.6.1-010	B
Electrical conductor insulation for inaccessible medium-voltage cables -typical operating range of 2 kV to 35 kV	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39)	VI.A.LP-35a	3.6.1-010	B

Table 3.6.2-1 Electrical Commodities (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fuse Holders (not part of active equipment): Electrical Insulation	Insulate (Electrical)	Electrical Insulation: Bakelite; Phenolic Melamine or Ceramic; Molded Polycarbonate; Other Organic Polymers	Air – Indoor, Controlled or Uncontrolled	None	None	VI.A.LP-24	3.6.1-022	I, 1
Fuse Holders (not part of active equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air - Indoor Uncontrolled	None	None	VI.A.LP-23	3.6.1-016	I, 2
			Air – Indoor, Controlled or Uncontrolled	None	None	VI.A.LP-31	3.6.1-018	I, 4
						VI.A.L-07	3.6.1-017	I, 3
High Voltage Electrical Insulators	Insulate (Electrical)	Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement	Air - Outdoor	None	None	VI.A.LP-32	3.6.1-002	I, 5
					None	VI.A.LP-28	3.6.1-003	I, 6
Metal Enclosed Bus: Bus/Connections	Electrical Continuity	Various Metals Used for Electrical Bus and Connections	Air – Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Electrical Resistance of Connection	Metal Enclosed Bus (B.2.1.42)	VI.A.LP-25	3.6.1-012	A
Metal Enclosed Bus: Electrical Insulation, Electrical Insulators	Insulate (Electrical)	Porcelain, Various Organic Polymers	Air – Indoor, Controlled or Uncontrolled, or Air - Outdoor	Reduced Electrical Insulation Resistance	Metal Enclosed Bus (B.2.1.42)	VI.A.LP-26	3.6.1-013	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air - Outdoor	Loss of Material	Metal Enclosed Bus (B.2.1.42)	VI.A.LP-42	3.6.1-015	A

Table 3.6.2-1 Electrical Commodities (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air – Indoor, Controlled or Uncontrolled	None	None	VI.A.LP-41	3.6.1-023	A
Switchyard Bus and Connections	Electrical Continuity	Aluminum, Stainless Steel, Copper, Bronze, Galvanized Steel	Air - Outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 7
Transmission Conductors	Electrical Continuity	Aluminum	Air - Outdoor	None	None	VI.A.LP-46	3.6.1-021	A, 8
		Aluminum, Steel	Air - Outdoor	None	None	VI.A.LP-38	3.6.1-004	I, 9
					None	VI.A.LP-47	3.6.1-007	I, 10
Transmission Connectors	Electrical Continuity	Aluminum, Steel	Air - Outdoor	None	None	VI.A.LP-48	3.6.1-005	I, 11
Wooden Pole	Structural Support	Treated Wood	Air - Outdoor	Loss of Material; Change in Material Properties	Wooden Pole (B.2.2.1)	III.A6.TP-223	3.5.1-062	E, 12
			Soil	Loss of Material; Change in Material Properties	Wooden Pole (B.2.2.1)	III.A6.TP-223	3.5.1-062	E, 12

Table 3.6.2-1 Electrical Commodities (Continued)

Notes	Definition of Note
A	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
B	Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
C	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.
D	Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F	Material not in NUREG-2191 for this component.
G	Environment not in NUREG-2191 for this component and material.
H	Aging effect not in NUREG-2191 for this component, material, and environment combination.
I	Aging effect in NUREG-2191 for this component, material, and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Plant Specific Notes:

1. In alignment with GALL-SLR, no aging management program is required when fuse holders are located in an environment that does not subject them to environmental aging mechanisms. Fuse holder insulation material in an adverse localized environment is managed via the XI.E1 AMP. PBAPS fuse holders (not in active components) insulation material and environment combination has no aging effects requiring management.

2. In alignment with GALL-SLR, no aging management program is required when fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation. See SLRA Section 3.6.2.3.1 for additional information.

3. In alignment with GALL-SLR, no aging management program is required when fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, or electrical transients. See SLRA Section 3.6.2.3.1 for additional information.

4. In alignment with GALL-SLR, no aging management program is required when fuse holders are not subject to fatigue due to frequent fuse removal/manipulation or removal. See SLRA Section 3.6.2.3.1 for additional information.

Table 3.6.2-1 Electrical Commodities (Continued)

Plant Specific Notes: (continued)

5. Based on PBAPS design and operating experience, loss of material is not an applicable aging effect for PBAPS high-voltage electrical insulators. In scope high-voltage electrical insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air – outdoor environment are not subject to mechanical wear or corrosion caused by wind blowing on transmission conductors. For more information see SLRA Section 3.6.2.3.2.

6. Based on PBAPS design and operating experience, reduced insulation resistance is not an applicable aging effect for PBAPS high-voltage electrical insulators. In scope high-voltage electrical insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air – outdoor environment are not subject to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume, or industrial effluent contamination. For more information see SLRA Section 3.6.2.3.2.

7. Based on PBAPS design and operating experience, loss of material and increased resistance of connection are not applicable aging effects for PBAPS switchyard bus and connections. In scope switchyard bus and connections comprised of aluminum and stainless steel in an air – outdoor environment are not subject to wind induced abrasion nor oxidation or loss of pre-load. For more information see SLRA Section 3.6.2.2.3, Further Evaluation.

8. Based on SRP-SLR Table 3.6-1 Item 021 and PBAPS design and operating experience, loss of conductor strength due to corrosion is not applicable for ACAR and All Aluminum Conductor (AAC). This line item is consistent with NUREG-2191.

9. Based on PBAPS design and operating experience, loss of material is not an applicable aging effect for PBAPS ACSR transmission conductors. In scope PBAPS transmission conductors comprised of aluminum and steel in an air – outdoor environment are not subject to wind induced abrasion. For more information see SLRA Section 3.6.2.2.3, Further Evaluation.

10. Based on PBAPS design and operating experience, loss of conductor strength is not an applicable aging effect for PBAPS ACSR transmission conductors. In scope PBAPS transmission conductors comprised of aluminum and steel in an air – outdoor environment are not subject to corrosion. For more information see SLRA Section 3.6.2.2.3, Further Evaluation.

11. Based on PBAPS design and operating experience, increased resistance of connection is not an applicable aging effect for PBAPS transmission connectors. In scope PBAPS transmission connectors comprised of stainless steel in an air – outdoor environment are not subject to oxidation or loss of pre-load. For more information see SLRA Section 3.6.2.2.3, Further Evaluation.

12. The Wooden Pole program (B.2.2.1) is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The Wooden Pole program is substituted for the GALL-SLR XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants program because the Wooden Pole program activities are specific to wooden utility poles, match the transmission and distribution industry standard for wooden pole condition monitoring, and are implemented by qualified personnel performing wooden pole condition monitoring for the grid surrounding PBAPS.

4.0 TIME-LIMITED AGING ANALYSES

4.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES (TLAAS)

Pursuant to 10 CFR 54.3, time-limited aging analyses (TLAAs) are those licensee calculations and analyses that:

1. Involve systems, structures, and components within the scope of license renewal;
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; and
6. Are contained or incorporated by reference in the current licensing basis (CLB).

4.1.1 IDENTIFICATION OF PBAPS TIME-LIMITED AGING ANALYSES

TLAAs have been identified for PBAPS using methods consistent with those provided in 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants (Reference 4.8.1) and NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP) (Reference 4.8.2).

Each potential TLAA was reviewed against the six criteria from 10 CFR 54.3(a) listed in SLRA Section 4.1 above. Those that meet all six criteria were identified as TLAAs that require evaluation for the second period of extended operation. While the current license term referred to in 10 CFR 54.3 is now 60 years for PBAPS, all TLAAs that were identified in the first License Renewal Application (LRA), based on a 40-year term, have been identified and evaluated.

A list of potential generic TLAAs was assembled from the SRP report, industry guidance and experience, including:

- NUREG-2191, Revision 0, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (Reference 4.8.3)
- NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (Reference 4.8.2)
- NEI 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule (Reference 4.8.4)
- NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal, March 2017 (Reference 4.8.42)

- The 10 CFR 54 Final Rule, Statement of Considerations
- Prior license renewal applications, NRC Requests for Additional Information, and NRC Safety Evaluation Reports for these applications.

CLB (Current License Basis) and design basis documentation were searched to identify potential TLAAs. The document search included the following:

- Updated Final Safety Analysis Report (UFSAR)
- Technical Specifications and Bases
- Docketed Licensing Correspondence, including those associated with the first LRA.
- NRC Safety Evaluation Reports (SERs)
- Design Baseline Documents (DBDs)
- General Electric and General Electric Hitachi (GEH) Design Analyses and Reports
- Bechtel Design Analyses and Reports
- Chicago Bridge and Iron Design Analyses and Reports
- Structural Integrity Associates Design Analyses and Reports
- Passport Component Record List
- Environmental Qualification Binders
- Engineering Specifications
- Engineering Change Requests
- Corrective Action Program Reports
- 10 CFR 50.12 Exemption Requests
- Inservice Inspection Relief Requests

4.1.2 EVALUATION OF PBAPS TIME-LIMITED AGING ANALYSES

Each PBAPS TLAA has been evaluated for the second period of extended operation. Each evaluation contains the following information:

TLAA Description: A description of the CLB analysis that has been identified as a TLAA, including a description of the aging effect evaluated, the time-limited variable used in the analysis, and its basis.

TLAA Evaluation: An evaluation of the TLAA for the second period of extended operation. This section provides information associated with 80 years of operation for comparison with the information used in the TLAA that considered the previous license term of operation. This evaluation provides the basis for the disposition, which falls into one of the three disposition categories described below.

TLAA Disposition: The disposition is classified in accordance with one of the acceptance criteria from 10 CFR 54.21(c)(1) specified below in Section 4.1.3.

4.1.3 ACCEPTANCE CRITERIA

10 CFR 54.21, Contents of application – technical information, states that an application must contain the following information:

(c) An evaluation of time-limited aging analyses.

(1) A list of time-limited aging analyses, as defined in §54.3, must be provided. The applicant shall demonstrate that:

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

One of these three methods was used to disposition each TLAA identified for the second period of extended operation for PBAPS. The methods used are identified in each TLAA evaluation section.

4.1.4 SUMMARY OF RESULTS

SLRA Table 4.1-1 lists the example TLAAs provided in NUREG-2192, Tables 4.1-2 and 4.7-1, and specifies whether or not they have been identified as TLAAs for PBAPS. Those examples with a "Yes" entry apply for PBAPS and the section(s) where the TLAA(s) are evaluated are provided. Those examples with a "No" entry do not apply for PBAPS and no TLAA was identified for these categories either because they are associated with design features not employed at PBAPS or because no analysis was identified that meet all six TLAA criteria.

SLRA Table 4.1-2 is a summary of the TLAAs identified for PBAPS. The TLAAs are grouped by affected component and aging effect analyzed. The table entries also state the disposition method used in evaluating the TLAA and include a reference to the applicable SLRA section where the TLAA is evaluated for the second period of extended operation.

4.1.5 IDENTIFICATION OF EXEMPTIONS PURSUANT TO 10 CFR 50.12

Exemptions pursuant to 10 CFR 50.12 currently in effect for PBAPS Unit 2 and Unit 3 were reviewed to determine if they are based upon a TLAA. There were no exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon or are associated with a TLAA.

Table 4.1-1 Review of Generic TLAAS Listed in NUREG-2192, Tables 4.1-2 and 4.7-1		
NUREG-2192 Examples of Potential Generic and Plant-Specific TLAAs	**Applies for PBAPS?**	**SLRA Section**
NUREG-2192, Table 4.1-2 – Generic TLAAs		
Neutron Fluence	Yes	4.2.1
Pressurized Thermal Shock (PWRs Only)	No	N/A
Upper Shelf Energy (PWRs and BWRs)	Yes	4.2.2
Pressure Temperature (P-T) Limits (PWRs and BWRs) Setpoints (PWRs Only)	Yes	4.2.4
Low Pressure Overpressure Protection System Setpoints (PWRs Only)	No	N/A
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
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	4.3.2 and 4.3.3
Metal Fatigue of Non-Class 1 Components	Yes	4.3.4
Environmentally-Assisted Fatigue	Yes	4.3.5
High Energy Line Break Analyses	Yes	4.3.7
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	4.3.8
Cycle-dependent Fatigue Waivers	Yes	4.3.3
Environmental Qualification of Electric Equipment	Yes	4.4
Concrete Containment Tendon Prestress	No	N/A
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	4.6

Table 4.1-1 Review of Generic TLAAS Listed in NUREG-2192, Tables 4.1-2 and 4.7-1		
NUREG-2192 Examples of Potential Generic and Plant-Specific TLAAs	**Applies for PBAPS?**	**SLRA Section**
NUREG-2192, Table 4.7-1 – Examples of Potential Plant-Specific TLAA Topics (BWRs)		
Reflood Thermal Shock of the Reactor Pressure Vessel	Yes	4.2.7
Reflood Thermal Shock of the Core Shroud and Other Reactor Vessel Internals	Yes	4.2.8
Loss of Preload for Core Plate Rim Hold-Down Bolts	Yes	4.2.9
Erosion of the Main Steam Line Flow Restrictors	No	N/A
Susceptibility to Irradiation-Assisted Stress Corrosion Cracking	Yes	4.2.14
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	No	N/A
Predicted Lower Limit	No	N/A

TABLE 4.1-2
SUMMARY OF RESULTS - PBAPS TIME-LIMITED AGING ANALYSES

TLAA DESCRIPTION	Disposition	SLRA SECTION
IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES (TLAAS)		4.1
Identification of PBAPS Time-Limited Aging Analyses		4.1.1
Evaluation of PBAPS Time-Limited Aging Analyses		4.1.2
Acceptance Criteria		4.1.3
Summary of Results		4.1.4
Identification of Exemptions Pursuant to 10 CFR50.12		4.1.5
REACTOR VESSEL AND INTERNALS NEUTRON EMBRITTLEMENT ANALYSES		4.2
Reactor Vessel Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.1
Reactor Vessel Internals Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.2
Reactor Vessel Upper-Shelf Energy (USE) Analyses	§54.21(c)(1)(ii)	4.2.2
Reactor Vessel Adjusted Reference Temperature (ART) Analyses	§54.21(c)(1)(ii)	4.2.3
Reactor Vessel Pressure-Temperature (P-T) Limits	§54.21(c)(1)(iii)	4.2.4
Reactor Vessel Circumferential Weld Failure Probability Analyses	§54.21(c)(1)(iii)	4.2.5
Reactor Vessel Axial Weld Failure Probability Analyses	§54.21(c)(1)(ii)	4.2.6
Reactor Vessel Reflood Thermal Shock Analysis	§54.21(c)(1)(ii)	4.2.7
Core Shroud Reflood Thermal Shock Analysis	§54.21(c)(1)(i)	4.2.8
Core Plate Rim Hold-Down Bolt Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.9
Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.10
Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.11
Jet Pump Riser Repair Clamp Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.12
Replacement Core Plate Plug Extended Life Irradiation –Enhanced Stress Relaxation Analysis	§54.21(c)(1)(ii)	4.2.13
First License Renewal Application Core Shroud IASCC and Embrittlement Analysis	§54.21(c)(1)(iii)	4.2.14
Unit 3 Core Spray Replacement Piping Bolting Loss of Preload Evaluation	§54.21(c)(1)(ii)	4.2.15
METAL FATIGUE ANALYSES		4.3
ASME Section III, Class 1 Fatigue Analyses	§54.21(c)(1)(iii)	4.3.2
ASME Section III, Class 1 Fatigue Waivers	§54.21(c)(1)(ii)	4.3.3
ASME Section III, Class 2, Class 3, and ANSI B31.1 Allowable Stress Analyses	§54.21(c)(1)(i)	4.3.4
Environmental Fatigue Analyses for RPV and Class 1 Piping	§54.21(c)(1)(iii)	4.3.5
Generic BWR Fatigue Analyses for Various Reactor Vessel Internal Components	§54.21(c)(1)(ii)	4.3.6.1
Generic BWR Fatigue Analyses for the Core Shroud	§54.21(c)(1)(i)	4.3.6.2
Core Shroud Support Fatigue Analysis Reevaluation	§54.21(c)(1)(iii)	4.3.6.3
Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis	§54.21(c)(1)(iii)	4.3.6.4
Replacement Steam Dryer Stress Report and Fatigue Evaluation	§54.21(c)(1)(i)	4.3.6.5
High-Energy Line Break (HELB) Analyses Based On Cumulative Fatigue Usage	§54.21(c)(1)(iii)	4.3.7
Inservice 60-Year RPV Closure Head Weld Flaw Analyses	§54.21(c)(1)(i)	4.3.8

TABLE 4.1-2 SUMMARY OF RESULTS - PBAPS TIME-LIMITED AGING ANALYSES		
TLAA DESCRIPTION	**Disposition**	**SLRA SECTION**
ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT		4.4
Environmental Qualification of Electric Equipment	§54.21(c)(1)(iii)	4.4.1
CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS		4.5
Concrete Containment Tendon Prestress Analysis	No TLAA	4.5.1
PRIMARY CONTAINMENT FATIGUE ANALYSES		4.6
Primary Containment Structures, Penetrations, and Associated Components with Fatigue Analyses	§54.21(c)(1)(iii)	4.6.1
Containment Process Line Penetration Bellows	§54.21(c)(1)(i)	4.6.2
OTHER PLANT-SPECIFIC ANALYSES		4.7
Cranes Cyclic Loading Analyses	§54.21(c)(1)(i)	4.7.1
Reactor Vessel Main Steam Nozzle Clad Removal Corrosion Allowance	§54.21(c)(1)(ii)	4.7.2
Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking”	§54.21(c)(1)(iii)	4.7.3
Fracture Mechanics of ISI-Reportable Indications for Group I Piping: As-Forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT	§54.21(c)(1)(ii)	4.7.4
Unit 3 Core Spray Replacement Piping Fatigue and Leakage Assessment	§54.21(c)(1)(i)	4.7.5

4.2 REACTOR VESSEL AND INTERNALS NEUTRON EMBRITTLEMENT ANALYSES

Reactor Pressure Vessel (RPV) Embrittlement TLAAs

10 CFR 50.60 (Reference 4.8.6) requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H (References 4.8.7 and 4.8.8). The ferritic materials of the reactor pressure 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 cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant).

Toughness (indirectly measured in foot-pounds of absorbed energy in a Charpy impact test) is temperature dependent in ferritic materials. An initial nil-ductility reference temperature (RT_{NDT}) is associated with the transition from ductile to brittle behavior and is determined for 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 of reactor pressure vessel steels. This means greater temperatures are required for the material to behave in a ductile manner.

To reduce the potential for brittle fracture during reactor pressure vessel operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for through the use of operating pressure-temperature (P-T) limits that are managed using a P-T Limits Report (PTLR). The P-T limits account for the decrease in material toughness of the reactor pressure vessel beltline materials associated with a given fluence. P-T limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to application of specified reactor pressure vessel pressures. The P-T limit curves are based, in part, upon Adjusted Reference Temperature (ART) values for each material located within the beltline region of the reactor vessel. The ART value is computed using the initial RT_{NDT} (nil-ductility temperature) and ΔRT_{NDT} (change in nil-ductility temperature due to fluence) computed for the licensed operating period, along with appropriate margins.

The beltline region includes the reactor vessel plates, welds and forging materials that are predicted to receive a cumulative neutron exposure of 1.0E+17 (1.0×10^{17}) neutrons/cm^2 through the end of the second period of extended operation. Since the cumulative neutron fluence will increase during the second period of extended operation, a review is required to determine if any additional components will exceed the threshold value and require evaluation for neutron embrittlement.

Based on the projected drop in toughness for each beltline material as a result of exposure to the predicted fluence values, USE calculations are performed to determine if the components will continue to have adequate fracture toughness at the end of license to meet the required minimums. Where the USE value for beltline materials does not meet the required minimum value, an Equivalent Margins Analysis is performed. The reactor pressure vessel material ART and USE values, calculated on the basis of neutron fluence, as well as the P-T limit curves based on the ART values, are part of the licensing basis and support safety determinations and therefore have been identified as TLAAs. The increases in RT_{NDT} (ΔRT_{NDT}) also affect the bases for relief from circumferential weld inspection and the supporting calculation of limiting axial weld conditional failure probability. Therefore, these calculations have been identified as TLAAs. A reflood thermal shock analysis for the RPV has been also identified that is based upon irradiated material properties derived using neutron fluence values as inputs. Therefore, these analyses have been identified as TLAAs.

The following TLAAs related to neutron embrittlement of the RPV are evaluated in the SLRA subsections listed below:

- Reactor Vessel Neutron Fluence Analyses (Section 4.2.1.1)
- Reactor Vessel Upper-Shelf Energy (USE) Analyses (Section 4.2.2)
- Reactor Vessel Adjusted Reference Temperature (ART) Analyses (Section 4.2.3)
- Reactor Vessel Pressure–Temperature (P-T) Limits (Section 4.2.4)
- Reactor Vessel Circumferential Weld Failure Probability Analyses (Section 4.2.5)
- Reactor Vessel Axial Weld Failure Probability Analyses (Section 4.2.6)
- Reactor Vessel Reflood Thermal Shock Analysis (Section 4.2.7)

RV Internal Component TLAAs

Several reactor vessel internal components, including core plate rim hold-down bolts and jet pump repair hardware components have been analyzed for loss of preload due to irradiation-enhanced stress relaxation due to neutron fluence and other aging mechanisms, which have also been identified as TLAAs that are evaluated in the SLRA subsections listed below:

- Reactor Vessel Internals Neutron Fluence Analyses (Section 4.2.1.2)
- Core Shroud Reflood Thermal Shock Analysis (Section 4.2.8)
- Core Plate Rim Hold-down Bolt Loss of Preload Analysis (Section 4.2.9)
- Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis (Section 4.2.10)
- Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis (Section 4.2.11)
- Jet Pump Riser Repair Clamp Loss of Preload Analysis (Section 4.2.12)
- Replacement Core Plate Extended Life Plug Irradiation-Enhanced Stress Relaxation Analysis (Section 4.2.13)
- First License Renewal Application Core Shroud IASCC and Embrittlement Analysis (Section 4.2.14)
- Unit 3 Core Spray Replacement Piping Bolting Loss of Preload Evaluation (Section 4.2.15)

Comparison to Neutron Embrittlement TLAAs Evaluated During the First License Renewal

During the first license renewal project, including the License Renewal Application (LRA) and subsequent responses to Requests for Additional Information (RAIs), each of the TLAAs associated with Reactor Pressure Vessel (RPV) neutron embrittlement listed above for Sections 4.2.1 through 4.2.7 were identified and evaluated for 60 years. The same method used to evaluate these TLAAs in the first license renewal project has been used to re-evaluate them for 80 years in this application. First, the neutron fluence values have been projected for 80 years, as described in Section 4.2.1.1. Then the 80-year fluence values have been 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.

The reactor vessel internals neutron embrittlement TLAAs listed above have been evaluated, as described in Sections 4.2.8 through 4.2.12, based upon 80-year fluence projections described in Section 4.2.1.2.

Section 4.2.1.3, which is not a TLAA, addresses a recent NRC concern related to the uncertainty of calculated fluence projections for RPV elevations above the active fuel.

4.2.1 REACTOR VESSEL AND INTERNALS NEUTRON FLUENCE ANALYSES

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 over a given period of time. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the loss of fracture toughness aging effect resulting from neutron fluence.

The NRC approved General Electric Hitachi (GEH) Discrete Ordinates Transfer (DORT) methodology has been used in developing the 60-year fluence projections and associated reactor vessel embrittlement analyses that account for an Extended Power Uprate (EPU) and implementation of the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy. Sixty-year fluence projections for Measurement Uncertainty Recapture (MUR) power uprate of 1.66 percent were conservatively scaled from MELLLA+ flux values based on the methodology in Licensing Topical Report (LTR) NEDC-32983P-A (Reference 4.8.9).

The current uprated power level of 4016 megawatts thermal (MWt) is the maximum power level evaluated for the second period of extended operation. Eighty-year fluence projections for the PBAPS reactor pressure vessels, which are conservatively scaled from the MUR projected flux values, are used in evaluating the neutron embrittlement TLAAs in SLRA Sections 4.2.2 through 4.2.7.

Transware Radiation Analysis Modeling Application (RAMA) methodology has been used to develop 80-year fluence projections for reactor vessel internal components that are used in evaluating reactor vessel internal component TLAAs in SLRA Sections 4.2.1.2 and 4.2.8 through 4.2.12. The basis for acceptability of each of these fluence projection methods is described in the applicable sections below. There has been no combination of the two methodologies applied to any component.

<u>PBAPS Power Level Background</u>

Below is a summary PBAPS historical operating power levels which have been considered in developing the 80-year fluence projections:

- The Original Licensed Thermal Power (OLTP) level for PBAPS Units 2 and 3 was 3293 MWt.

- By Amendment Nos. 198 and 211 (Units 2 and 3 respectively), the NRC approved an approximate 5 percent stretch power uprate to 3458 MWt in the mid-1990s.

- By Amendment Nos. 247 and 250 (Units 2 and 3, respectively) dated November 22, 2002, the NRC approved a 1.62 percent measurement uncertainty recapture (MUR) uprate that authorized an increase in the maximum thermal power level from 3458 MWt to 3514 MWt.

- By Amendment Nos. 293 and 296 (Units 2 and 3, respectively) dated August 25, 2014, the NRC approved a 12.4 percent EPU (Extended Power Uprate) that authorized an increase in the maximum thermal power level from 3514 MWt to the licensed thermal power (CLTP) level of 3951 MWt. The EPU power level of 3951 MWt represents an increase of approximately 20 percent above the OLTP level of 3293 MWt.

- By Amendment Nos. 305 and 309 (Units 2 and 3, respectively), dated March 21, 2016 the NRC approved a Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy in 2016 for both units in accordance with NEDC-33006P-A for both units. (Reference 4.8.10)

- By Amendment Nos. 316 and 319 (Units 2 and 3, respectively) dated November 15, 2017, the NRC approved a 1.66 percent Measurement Uncertainty Recapture (MUR) power uprate to 4016 MWt at mid-Cycle 22 for Unit 2 and at the beginning of Cycle 22 for Unit 3. This is the current licensed thermal power limit for PBAPS.

4.2.1.1 REACTOR VESSEL NEUTRON FLUENCE ANALYSES

TLAA Description:

Fluence projections developed using the NRC approved General Electric Hitachi (GEH) Discrete Ordinate Transfer (DORT) methodology have been used as inputs in the current licensing basis RPV neutron embrittlement analyses for Unit 2 and Unit 3 beltline components, including analyses of Upper Shelf Energy (USE), Adjusted Reference Temperatures (ART), Pressure-Temperature (P-T) limits, axial and circumferential weld failure probability, and RPV reflood thermal shock. The most recent fluence projection analyses, reported in the PBAPS MUR license amendment request (Reference 4.8.57), were developed for 60 years and 54 EFPY.

The fluence projections associated with the MUR power level of 4016 MWt were used in the current 60-year RPV neutron embrittlement analyses for PBAPS Units 2 and 3 (Reference 4.8.57). The MUR fluence projections were scaled from the MELLLA+ flux values which were based on the methodology in Licensing Topical Report (LTR) NEDC-32983P-A (Reference 4.8.9), which was approved by the NRC in a Safety Evaluation Report (SER) for referencing in licensing actions dated September 14, 2001 (Reference 4.8.11) and in a final SER dated November 17, 2005 (Reference 4.8.12). The GEH methodology described in the LTR adheres to the guidance in Regulatory Guide 1.190 (Reference 4.8.13) for neutron flux evaluation. These current fluence analyses have been identified as TLAAs that require evaluation for the second period of extended operation.

TLAA Evaluation:

The first step in updating fluence projections from 60 years to 80 years was to update the Effective Full Power Year (EFPY) projections, based upon past power history records, including capacity factors and power production data. In order to determine the number of EFPY applicable for 80 years, a review of cumulative neutron exposure and EFPY through recent completed operating cycles for each unit was performed. As of December 2, 2014, Unit 2 accumulated 29.98 EFPY at the end of the unit's 20th operating cycle and as of October 22, 2015, Unit 3 accumulated 30.69 EFPY at the end of the unit's 20th operating cycle. Therefore, Unit 2 is projected to reach 68.7 EFPY in 80 years and Unit 3 is projected to reach 69.4 EFPY in 80 years assuming each unit operates at 100 percent capacity (no outages) from December 2, 2014 for Unit 2 and October 22, 2015 for Unit 3, through the end of the second period of extended operation. Based upon the review, 70 EFPY was determined to be a conservative value to use in projecting the 80-year fluence values to be used in evaluating the neutron embrittlement TLAAs in Section 4.2 of the SLRA.

The 70 EFPY fluence projections have been developed by first compiling cumulative fluence resulting from each past operating cycle and then adding the predicted fluence for future operating cycles through the second period of extended operation. The predicted fluence for future operating cycles through the second period of extended operation was determined by scaling the 60-year MELLLA+ flux values to account for MUR and multiplying by the remaining EFPYs to reach 70 EFPY. No additional RPV plates, welds, or nozzles have been added to the beltline of either unit since all components exceeding 1.0E+17 n/cm^2 at 70 EFPY were previously included within the beltline of each unit, including the N16 A & B Water Level Instrumentation (WLI) nozzles, as shown in Figure 4.2.1-1 for Unit 2 and Figure 4.2.1-2 for Unit 3.

For Unit 2, the upper edge of the beltline at 70 EFPY will extend to elevation 383.2 inches above Vessel "0 inches", as compared to 380.08 inches at 54 EFPY. The lower edge of the beltline at 70

EFPY will extend down to 203.6 inches above Vessel “0 inches”, as compared to 204.59 inches at 54 EFPY.

For Unit 3, the upper edge of the beltline at 70 EFPY will extend to elevation 382.9 inches above Vessel “0 inches”, as compared to 380.10 inches at 54 EFPY. The lower edge of the beltline at 70 EFPY will extend down to 203.9 inches above Vessel “0 inches”, as compared to 204.60 inches at 54 EFPY.

The 70 EFPY fluence projections are provided in the following tables:

1. SLRA Table 4.2.1.1-1, PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 70 EFPY (n/cm^2)

2. SLRA Table 4.2.1.1-2, PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 70 EFPY (n/cm^2)

3. SLRA Table 4.2.1.1-3, PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 70 EFPY (n/cm^2)

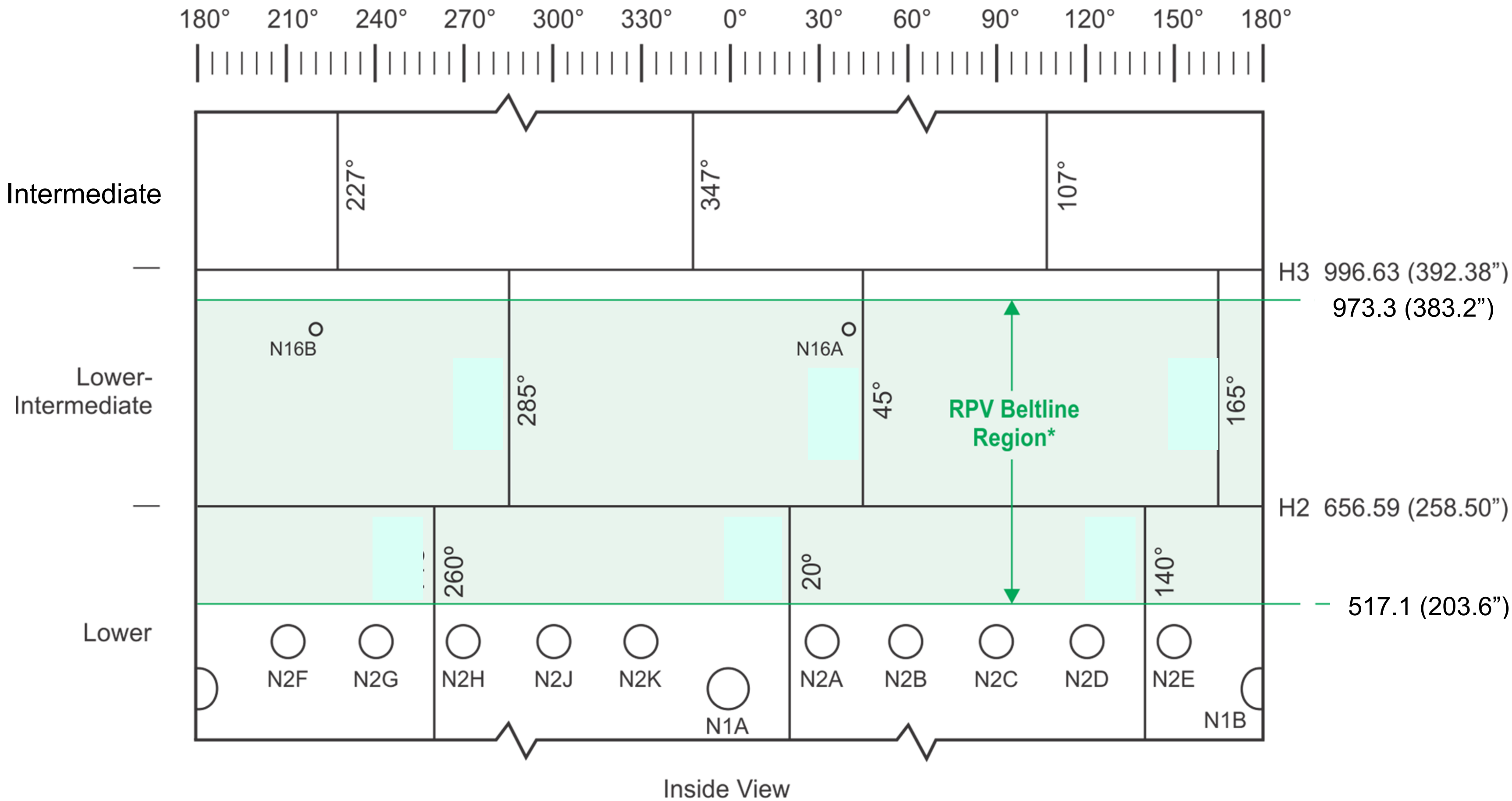
4. SLRA Table 4.2.1.1-4, PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 70 EFPY (n/cm^2)

5. SLRA Table 4.2.1.1-5, PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 70 EFPY (n/cm^2)

6. SLRA Table 4.2.1.1-6, PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 70 EFPY (n/cm^2)

These 70 EFPY fluence projections will be validated by the Neutron Fluence Monitoring (B.3.1.2) aging management program during the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The Unit 2 and Unit 3 RPV beltline component fluence analyses have been satisfactorily projected through the second period of extended operation. They are to be used as inputs in the Reactor Vessel neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.7.



Notes: This drawing is not to scale
Dimensions are given in centimeters (inches)
* RPV beltline is shown for 70 EFPY

Figure 4.2.1-1 – PBAPS Unit 2 - Reactor Vessel - Beltline Components

Table 4.2.1.1-1
PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 70 EFPY (n/cm^2)

Plate No.	Heat Number	0T	1/4T
Unit 2 Lower Shell Plates:			
Mark 57	C2791-2	1.68E+18	1.16E+18
Mark 57	C2761-1	1.68E+18	1.16E+18
Mark 57	C2873-2	1.68E+18	1.16E+18
Unit 2 Lower-Intermediate Shell Plates:			
Mark 58	C2894-2	2.23E+18	1.54E+18
Mark 58	C2873-1	2.23E+18	1.54E+18
Mark 58	C2761-2	2.23E+18	1.54E+18

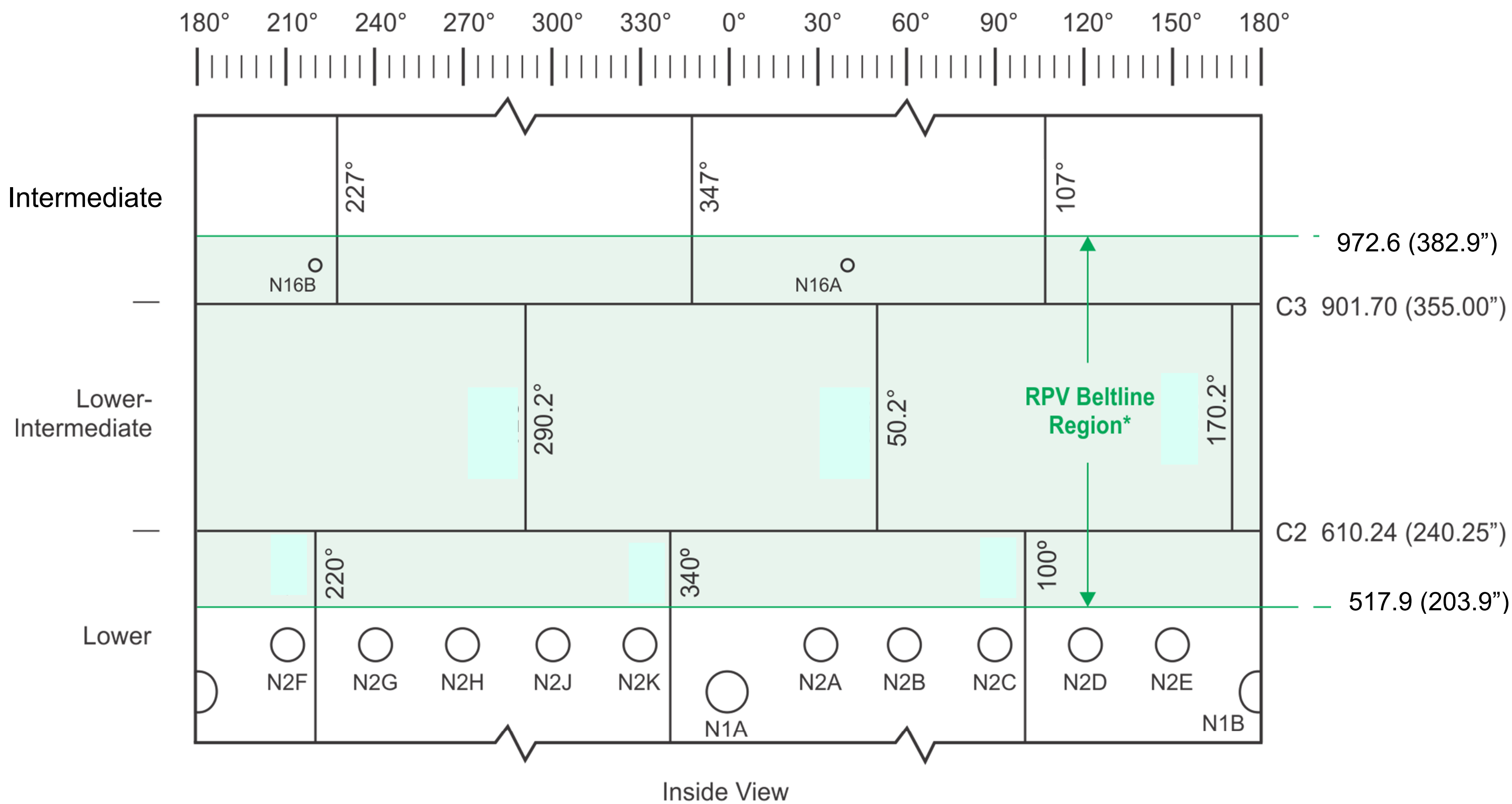
Table 4.2.1.1-2
PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 70 EFPY (n/cm^2)

Weld No.	Heat / Lot Number	0T	1/4T
Unit 2 Lower Shell Axial Welds:			
B1, B2, & B3	37C065	1.68E+18	1.16E+18
Unit 2 Lower-Intermediate Shell Axial Welds:			
C1, C2, & C3	37C065	2.23E+18	1.54E+18
Unit 2 Lower Shell-to-Lower Intermediate Shell Circumferential Weld:			
BC	S-3986 / Linde 124 Lot 3876	1.68E+18	1.16E+18

Table 4.2.1.1-3
PBAPS Unit 2 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 70 EFPY (n/cm^2)

Nozzle Location	Heat Number	0T	1/4T
Unit 2 N16 Water Level Instrumentation (WLI) Nozzles and Welds:			
N16 Nozzle Forging	C2873-1 **[1]**	7.65E+17	5.30E+17
N16 Nozzle Weld	N/A **[1]**	N/A	N/A

Note 1: The N16 Water Level Instrumentation nozzle forging and weld are fabricated from Nickel Alloy 600 material which does not require evaluation of loss of fracture toughness. Instead evaluation of loss of fracture toughness of the surrounding ferritic shell material is completed in later sections. The heat number of the surrounding material is provided.



Notes: This drawing is not to scale
Dimensions are given in centimeters (inches)
* RPV beltline is shown for 70 EFPY

Figure 4.2.1-2 – PBAPS Unit 3 - Reactor Vessel - Beltline Components

Table 4.2.1.1-4
PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 70 EFPY (n/cm^2)

Shell	Heat Number	0T	1/4T
Unit 3 Lower Shell Plates:			
6-146-1	C4689-2	1.27E+18	8.79E+17
6-146-3	C4684-2	1.27E+18	8.79E+17
6-146-7	C4627-1	1.27E+18	8.79E+17
Unit 3 Lower-Intermediate Shell Plates:			
6-139-10	C2773-2	2.14E+18	1.48E+18
6-139-11	C2775-1	2.14E+18	1.48E+18
6-139-12	C3103-1	2.14E+18	1.48E+18
Unit 3 Intermediate Shell Plates:			
6-146-5	C4608-1	1.32E+18	9.14E+17
6-146-4	C4689-1	1.32E+18	9.14E+17
6-146-2	C4654-1	1.32E+18	9.14E+17

Table 4.2.1.1-5
PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 70 EFPY (n/cm^2)

Weld No.	Heat/Lot Number	0T	1/4T
Unit 3 Lower Shell Axial Welds:			
D1, D2, & D3	37C065	1.27E+18	8.79E+17
Unit 3 Lower-Intermediate Shell Axial Welds:			
E1, E2, & E3	37C065	2.14E+18	1.48E+18
Unit 3 Intermediate Shell Axial Welds			
F1, F2, & F3	37C065	1.32E+18	9.14E+17
Unit 3 Lower-to-Lower-Intermediate Shell Circumferential Weld:			
DE	3P4000/ Linde 124 Lot 3932	1.27E+18	8.79E+17
Unit 3 Lower Intermediate-to-Intermediate Shell Circumferential Weld:			
EF	1P4217/ Linde 124 Lot 3929	1.32E+18	9.14E+17

Table 4.2.1.1-6
PBAPS Unit 3 - Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 70 EFPY (n/cm^2)

Nozzle No. / Location	Heat/Lot Number	0T	1/4T
Unit 3 N16 Water Level Instrumentation (WLI) Nozzles and Welds:			
N16 Nozzle Forging	C4689-1 **[1]**	7.35E+17	5.09E+17
N16 Nozzle Weld	N/A **[1]**	N/A	N/A

Note 1: The N16 Water Level Instrumentation nozzle forging and weld are fabricated from Nickel Alloy 600 material which does not require evaluation of loss of fracture toughness. Instead evaluation of loss of fracture toughness of the surrounding ferritic shell material is completed in later sections. The heat number of the surrounding material is provided.

4.2.1.2 REACTOR VESSEL INTERNALS NEUTRON FLUENCE ANALYSES

TLAA Description:

Neutron fluence exposure has been used as input in analyses of PBAPS Units 2 and 3 reactor vessel internals components, including the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware). 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 neutron fluence exposure is time dependent, these analyses have been identified as TLAAs that require evaluation for the second period of extended operation.

TLAA Evaluation:

Fluence projections for 80 years at a projected 70 EFPY have been developed to evaluate the neutron fluence dependent TLAAs associated with reactor vessel internals components in SLRA Sections 4.2.8 through 4.2.12. These fluence projections assumed an approximate 1.66 percent MUR power uprate to 4018 Mwt as of January 2018 for Units 2 and 3, through the second period of extended operation. The approved maximum thermal power output in amendment number 316 and 319 is 4016 Mwt. These 80-year projections are based on the Transware Radiation Analysis Modeling Application (RAMA) Fluence Methodology.

RAMA was developed by Transware Enterprises and is described in BWRVIP-114-A (Reference 4.8.14). The Staff reviewed BWRVIP-114-A in May 2005 (Reference 4.8.15) and concluded that licensees using the RAMA methodology for the calculation of neutron fluence at reactor internals locations must reference, or provide, an analysis which adequately benchmarks the use of the RAMA methodology for uncertainty and calculational bias based on the consideration of: (1) the location at which the neutron fluence is being calculated, (2) the geometry of the reactor, and (3) the accuracy required for the evaluation.

In February 2008, the Staff reviewed BWRVIP-145-A which documented the use of RAMA methodology to calculate fluence values for the core shroud and top guide samples removed from Susquehanna Unit 2 after 11 cycles of irradiation. The report compares the measured fluence results from the Susquehanna samples with the corresponding RAMA calculated fluence values. The Staff concluded there was reasonable agreement between the calculated fluence values and measured fluence values. The Staff found that for applications related to IASCC, crack propagation rates, and weldability determinations, the RAMA methodology can be used to determine the fast neutron fluence values in the core shroud and top guide (References 4.8.16, 4.8.17, and 4.8.18).

BWRVIP-145-A and the associated Staff SER (Reference 4.8.16) are referenced here for satisfying the location, geometry, and accuracy requirements specified in the SER for BWRVIP-114-A (Reference 4.8.15). The PBAPS Unit 2 and Unit 3 reactors are of the same BWR/4 design as Susquehanna Unit 2, with 251-inch inside diameter reactors, 764 fuel bundles (Reference 4.8.20), and core shrouds with a 207.125 inch outside diameter (Reference 4.8.21). Since there are similarities in vessel and internals dimensions, and the same RAMA methodology is used, the resulting fluence calculation accuracies for PBAPS internals are comparable to those presented in BWRVIP-145-A. Therefore, use of RAMA methodology to calculate projected fluence values for the PBAPS reactor vessel internal components, such as the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware) is acceptable.

These 80-year fluence projections for reactor vessel internals components are independent from the 80-year GEH fluence projections used in evaluating the PBAPS reactor vessels. The 80-year RAMA fluence projections for some Unit 2 and Unit 3 Reactor Vessel internal components are provided in the following tables.

- SLRA Table 4.2.1.2-1, Unit 2 RV Internal Component Fluence Projections
- SLRA Table 4.2.1.2-2, Unit 3 RV Internal Component Fluence Projections

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The Unit 2 and Unit 3 reactor vessel internal component fluence analyses have been satisfactorily projected through the second period of extended operation. They are to be used as inputs in the reactor vessel internal components fluence-related TLAA evaluations in Sections 4.2.8 through 4.2.12.

Table 4.2.1.2-1
Unit 2 RV Internal Component Fluence Projections

Component	70 EFPY Fluence (n/cm^2)
Core Plate Rim Hold-Down Bolt	8.10E+20
Jet Pump Slip Joint Clamp	1.17E+19
Jet Pump Auxiliary Spring Wedge Assembly	1.53E+20
Jet Pump Riser Weld RS-1	5.31E+15

Table 4.2.1.2-2
Unit 3 RV Internal Component Fluence Projections

Component	70 EFPY Fluence (n/cm^2)
Core Support Plate Rim Bolt at the Top of the Bolt	8.05E+20
Jet Pump Auxiliary Spring Wedge Assembly	8.12E+18
Jet Pump Riser Weld RS-1	5.29E+15

4.2.1.3 RPV FLUENCE ANALYSES

The RPV extended beltline elevations are the upper and lower elevations bounding the region of the RPV vessel where fluence values are projected to equal or exceed 1.0E+17 n/cm2 at 70 EFPY.

NUREG-2192 and 10 CFR 50.60 recommend fracture toughness evaluations of RPV components which are projected to experience fluence values of 1.0E+17 n/cm^2 or more. RPV fluence and upper extended beltline elevation projections for 80 years at 70 EFPY were performed using the GEH DORT methodology as described in Section 4.2.1.1. Fracture toughness evaluations of RPV components within the extended beltline elevations are described in Section 4.2.2 through 4.2.7.

The Neutron Fluence Monitoring (B.3.1.2) aging management program is an existing condition monitoring program that monitors and tracks neutron fluence to RPV components to ensure that fluence projections described on Section 4.2.1.1 remain valid through second period of extended operation.

Sensitivity evaluations have been performed to address a recent NRC concern that fluence projections above the active fuel region may have greater uncertainty than fluence projections for RPV elevations within the active fuel region. The concern is that water density sensitivity analyses described in Section 7.1, “Calculation Uncertainties” of NEDC-32983P-A, Revision 2 (reference 4.8.74), are not applicable to the above core water density distribution because the generically approved calculational model does not extend above the active fuel region based on Figure 2-2 of in NEDC-32983P-A, Revision 2. Also, projected fluence results for RPV elevations above the active fuel have not been benchmarked. Non-conservative fluence projections could potentially result in a non-conservatively low upper extended beltline elevation and exclude the metallurgical evaluation of portions of the RPV that will actually be exposed to 1.0E+17 n/cm^2 or more, prior to the end of the period of extended operation.

Because of this uncertainty, work is ongoing with the ANS 19.10 standards committee to revise the guidance within RG 1.190 to more explicitly outline its expectations for fluence projections within the upper plenum. Further, the sensitivity evaluations discussed below provide reasonable assurance that all components that may experience fluence values of 1.0E+17 n/cm^2 or more, meet established metallurgical acceptance criteria.

As shown on Figure 4.2.1-1, for Unit 2, the calculated 70 EFPY upper extended beltline elevation of approximately 383 inches resulted in the successful metallurgical evaluation of: all the lower-intermediate vessel wall plates, all the lower vessel wall plates, all the V1A/B/C and all V2A/B/C axial welds, the H2 circumferential weld, and the N16 nozzles, as described in Sections 4.2.2 through 4.2.7.

The Unit 2 intermediate plates, the H3 circumferential weld, and V3 axial welds are located 9 inches (elevation 392 inches) above the upper extended beltline elevation and have not been metallurgically evaluated in Sections 4.2.2 through 4.2.7. Although it is not reasonable that the uncertainty associated with the NRC’s concern would result in the extension of the upper extended beltline elevation for an additional 9 inches (elevation 392 inches) at 70 EFPY, a supplemental metallurgical sensitivity evaluation and justification was performed on all the Unit 2 intermediate plates, the H3 circumferential weld, and all V3A/B/C axial welds. Results of the supplemental metallurgical sensitivity evaluation concluded that, even with a postulated fluence value that is more than 20 times greater than expected, these reactor vessel components meet all the established metallurgical acceptance criteria for ART, USE/EMA, circumferential weld inspection relief, axial weld probability, and reflood thermal shock.

As shown on Figure 4.2.1-2, the Unit 3 lower-intermediate plates, are 38 inches shorter than the Unit 2 lower-intermediate plates. As a result, the Unit 3 projected upper extended beltline elevation (elevation 383 inches) extends onto portions of the intermediate plates and V3A/B/C welds and envelops the Unit 3 H3 weld, while for Unit 2 the upper extended beltline elevation does not reach these components. Therefore, for Unit 3, the calculated 70 EFPY upper extended beltline elevation resulted in the successful metallurgical evaluation of: all the intermediate vessel wall plates, all the lower-intermediate vessel wall plates, all the lower vessel wall plates, all the V1A/B/C, V2A/B/C, and V3A/B/C axial welds, the H2 and H3 circumferential weld, and the N16 nozzles, as described in Sections 4.2.2 through 4.2.7.

Unlike the Unit 2 intermediate plates, V3A/B/C welds, and H3 weld, which are located above the Unit 2 upper extended beltline elevation of 383 inches and therefore excluded from fracture toughness evaluation described in Sections 4.2.2 through 4.2.7, the Unit 3 intermediate plates and V3A/B/C welds which extend above elevation 443 inches, and H3 weld located at elevation 335 inches are evaluated for fracture toughness as described in Sections 4.2.2 through 4.2.7. Nevertheless, because of the uncertainty associated with the NRC’s concern, a supplemental metallurgical sensitivity evaluation and justification was performed on all the Unit 3 intermediate plates and associated welds. Results of the supplemental metallurgical sensitivity evaluation concluded that, even with a postulated fluence value that is more than 20 times greater than expected, these reactor vessel components meet all the established metallurgical acceptance criteria for ART, USE/EMA, circumferential weld inspection relief, axial weld probability, and reflood thermal shock.

The supplemental metallurgical sensitivity evaluation does not introduce additional Units 2 and 3 RPV components, that require fracture toughness evaluation per the recommendations in NUREG-2192 and 10 CFR 50.60. The supplemental metallurgical sensitivity evaluation serves as an analysis and justification that provides reasonable confidence that RPV components above approximately 383 inches would meet the established metallurgical acceptance criteria should future industry resolution of the concern result in the extension of the upper extended beltline elevation by more than 9 inches.

The Unit 2 and Unit 3 N9 nozzles are the lowest RPV components above the upper extended beltline elevation that have not been metallurgically evaluated in section 4.2.2 through 4.2.7 or in the supplemental metallurgical sensitivity evaluation. These are single 4-inch Control Rod Drive Hydraulic System Return nozzles located approximately 60 inches (elevation 443 inches) above the established upper extended beltline elevation of approximately 383 inches. It is not credible that the uncertainty associated with the NRC’s concern would result in an extension of the upper extended beltline elevation for an additional 60 inches (elevation 443 inches).

This NRC concern has been entered in to the PBAPS corrective action program. Results from industry activities associated with the ANS 19.10 standards committee will be incorporated into the Neutron Fluence Monitoring (B.3.1.2) aging management program as appropriate.

4.2.2 REACTOR VESSEL UPPER-SHELF ENERGY (USE) ANALYSES

TLAA Description:

Appendix G of 10 CFR 50, (Reference 4.8.7) Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy upper-shelf energy of no less than 75 ft-lb initially and must maintain Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The PBAPS Units 2 and 3 reactor vessels were designed and fabricated prior to the current requirements going into effect, and as a result, there is insufficient data available to establish the unirradiated USE value for all beltline materials for these reactors. Therefore, the current licensing basis Charpy USE evaluations are based upon Equivalent Margin Analysis (EMA) as specified in BWRVIP-74-A (Reference 4.8.22), which meet the alternative requirements specified above. Since the EMA values determined to evaluate USE for 60 years are based upon 54 EFPY fluence values, these analyses have been identified as TLAAs requiring evaluation for the second period of extended operation.

TLAA Evaluation:

In order to evaluate USE for 80 years, the 70 EFPY fluence values described in Section 4.2.1 for Units 2 and 3 reactor beltline materials have been used to develop revised EMA values that have been compared to the applicable design limits from BWRVIP-74-A. The EMA was performed for the limiting beltline plate and weld materials for 80 years of operation (70 EFPY), and compared against the 54 EFPY limits defined in Appendix B of BWRVIP-74-A. USE for the Water Level Instrument (WLI) nozzle is based upon the shell plates surrounding the nozzles because the forging is fabricated from Alloy 600 materials.

- SLRA Table 4.2.2-1 summarizes the 60-year EMA values, the 80-year EMA values, and the design limits for the limiting Unit 2 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-2 summarizes the 60-year EMA values, the 80-year EMA values, and the design limits for the limiting Unit 3 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-3 provides the EMA for the limiting Unit 2 plate materials.
- SLRA Table 4.2.2-4 provides the EMA for the limiting Unit 2 weld materials.
- SLRA Table 4.2.2-5 provides the EMA for the limiting Unit 3 plate materials.
- SLRA Table 4.2.2-6 provides the EMA for the limiting Unit 3 weld materials.

10 CFR 50, Appendix G (Reference 4.8.7), only requires USE evaluations for ferritic beltline materials. The N16 Water Level Instrument nozzles are partial penetration forgings fabricated from Nickel Alloy 600, which is not a ferritic material, and therefore do not require evaluation. The N16 nozzle partial penetration welds were also made using nickel alloy material. Therefore, the properties of the surrounding plate material and fluence at the N16 nozzle

location are used to determine the decrease in USE applicable for the N16 nozzle location. However, since this plate material is evaluated using fluence values that are bounding for the N16 nozzle locations, the EMA values for the plate material are also bounding for the nozzles.

The USE values for Unit 2 and Unit 3 reactor vessel beltline materials have been satisfactorily evaluated for the second period of extended operation based upon the updated EMA values determined using 80-year (70 EFPY) fluence projections.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The reactor vessel USE analyses have been satisfactorily projected through the second period of extended operation.

Table 4.2.2-1
Comparison of Unit 2 60-Year USE to 80-Year USE for Limiting Beltline Materials [1, 2]

Item	Analysis	Limiting Beltline Material	60-Year % Decrease in USE	80-Year % Decrease in USE	Allowable % Decrease Design Limit from BWRVIP-74-A	80-Year to 60-Year Comparison
1	Unit 2 USE/EMA	Plate Heat C2894-2	13.5	14.5	23.5	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits
2	Unit 2 USE/EMA	Weld Heat 37C065 **[3]**	20.0	21.5	39.0	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits
3	Unit 2 USE/EMA	N16 Forging Material **[4]**	13.5	14.5	23.5	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits

NOTES:
Note 1: PBAPS Units 2 and 3 require USE evaluation in accordance with Equivalent Margin Analysis (EMA) because there is insufficient data available to establish an unirradiated USE value for all beltline materials.
Note 2: The design limit for USE is 50 ft-lbs at the end-of-license. The EMA method described in BWRVIP-74-A provides the design limits based upon percent decrease in USE that equates to the 50 ft-lbs requirement. For 60 years of operation, the plate limit is 23.5% and the weld limit is 39%. The 80-year values for percent decrease in USE have been demonstrated to remain below the 60-year (54 EFPY) limits.
Note 3: Weld Heat 37C065 is an electroslag weld (ESW).
Note 4: The N16 nozzle is a partial penetration forging that is fabricated from Nickel Alloy 600 material, which does not require evaluation for fracture toughness. Therefore, the properties of the surrounding plate material and fluence at the N16 nozzle location are used to determine the decrease in USE. However, since this limiting plate material is already evaluated in Item 1 and since the fluence at the N16 nozzle location is less than the limiting fluence at the lower edge of this shell plate, the percent decrease previously determined for the plate is also bounding for the nozzle, as shown in Item 3.

Table 4.2.2-2
Comparison of Unit 3 60-Year USE to 80-Year USE for Limiting Beltline Materials [1,2]

Item	Analysis	Limiting Beltline Material	60-Year % Decrease in USE	80-Year % Decrease in USE	Allowable % Decrease Design Limit from BWRVIP-74-A	80-Year to 60-Year Comparison
1	Unit 3 USE/EMA	Plate Heat C2773-2	14.5	15.5	23.5	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits
2	Unit 3 USE/EMA	Weld Heat 37C065 **[3]**	19.5	21.0	39.0	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits
3	Unit 3 USE/EMA	N16 Forging Material **[4]**	14.5	15.5	23.5	The percent decrease is larger due to 80-year fluence but the USE/EMA remains within the prescribed 54 EFPY limits

NOTES:
Note 1: PBAPS Units 2 and 3 require USE evaluation in accordance with Equivalent Margin Analysis (EMA) because there is insufficient data available to establish an unirradiated USE value for all beltline materials.
Note 2: The design limit for USE is 50 ft-lbs at the end-of-license. The EMA method described in BWRVIP-74-A provides the design limits based upon percent decrease in USE that equates to the 50 ft-lbs requirement. For 60 years of operation, the plate limit is 23.5% and the weld limit is 39%. The 80-year values for percent decrease in USE have been demonstrated to remain below the 60-year (54 EFPY) limits.
Note 3: Weld Heat 37C065 is an electroslag weld (ESW).
Note 4: The N16 nozzle is a partial penetration forging that is fabricated from Nickel Alloy 600 material, which does not require evaluation for fracture toughness. Therefore, the properties of the surrounding plate material and fluence at the N16 nozzle location are used to determine the decrease in USE. However, since this limiting plate material is already evaluated in Item 1 and since the fluence at the N16 nozzle location is less than the limiting fluence at the lower edge of this shell plate, the percent decrease previously determined for the plate is also bounding for the nozzle, as shown in Item 3.

Table 4.2.2-3
Unit 2 Equivalent Margin Analysis for 70 EFPY
BWR/3-6 Plate

ISP Surveillance Program Plate USE (Heat C2761-2):		
%Cu	=	0.10
Unirradiated USE	=	127.2 ft-lb
1st Capsule Measured USE	=	133.0 ft-lb
1st Capsule Fluence	=	1.8E+17 n/cm^2
1st Capsule Measured % Decrease	=	-4.6 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	8.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C2894-2):		
%Cu	=	0.13
70 EFPY 1/4T Fluence	=	1.54E+18 n/cm^2
RG 1.99 Predicted % Decrease	=	14.5 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
% Decrease Limit from BWRVIP-74-A	=	23.5
Comparison of Limiting % Decrease Value to Limit:		
14.5%	**≤**	**23.5%**
Therefore, Unit 2 vessel plates are bounded by Equivalent Margin Analysis		

Table 4.2.2-4
Unit 2 Equivalent Margin Analysis for 70 EFPY
BWR/2-6 Weld

ISP Surveillance Weld USE (Heat PB2 ESW):		
%Cu	=	0.10
Unirradiated USE	=	110.9 ft-lb
1st Capsule Measured USE	=	113.6 ft-lb
1st Capsule Fluence	=	1.8E+17 n/cm^2
1st Capsule Measured % Decrease	=	-2.4 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Weld USE (Heat 37C065):		
%Cu	=	0.182
70 EFPY 1/4T Fluence	=	1.54E+18 n/cm^2
RG 1.99 Predicted % Decrease	=	21.5 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
% Decrease Limit from BWRVIP-74-A	=	39.0
Comparison of Limiting % Decrease Value to Limit:		
21.5%	**≤**	**39.0%**
Therefore, Unit 2 vessel welds are bounded by Equivalent Margin Analysis		

Table 4.2.2-5
Unit 3 Equivalent Margin Analysis for 70 EFPY
BWR/3-6 Plate

ISP Surveillance Program Plate USE (Heat B0673-1):		
%Cu	=	0.15
Unirradiated USE	=	158.1 ft-lb
1st Capsule Measured USE	=	158.8 ft-lb
1st Capsule Fluence	=	5.1E+17 n/cm^2
2nd Capsule Measured USE	=	137.0 ft-lb
2nd Capsule Fluence	=	1.17E+18 n/cm^2
3rd Capsule Measured USE	=	133.0 ft-lb
3rd Capsule Fluence	=	1.87E+18 n/cm^2
4th Capsule Measured USE	=	131.3 ft-lb
4th Capsule Fluence	=	2.63E+18 n/cm^2
1st Capsule Measured % Decrease	=	-0.4 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	13.4 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	14.5 (RG 1.99, Rev. 2, Figure 2)
3rd Capsule Measured % Decrease	=	15.9 (Charpy Curves)
3rd Capsule RG 1.99 Predicted % Decrease	=	16.5 (RG 1.99, Rev. 2, Figure 2)
4th Capsule Measured % Decrease	=	17.0 (Charpy Curves)
4th Capsule RG 1.99 Predicted % Decrease	=	18.0 (RG 1.99, Rev. 2, Figure 2)
(Table continued on next page)		

Table 4.2.2-5 (Continued) Unit 3 Equivalent Margin Analysis for 70 EFPY BWR/3-6 Plate		
Limiting Beltline Plate USE (Heat C2773-2):		
%Cu	=	0.15
70 EFPY 1/4T Fluence	=	1.48E+18 n/cm^2
RG 1.99 Predicted % Decrease	=	15.5 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
% Decrease Limit from BWRVIP-74-A	=	23.5
Comparison of Limiting % Decrease Value to Limit:		
15.5%	**≤**	**23.5%**
Therefore, Unit 3 vessel plates are bounded by Equivalent Margin Analysis		

Table 4.2.2-6 Unit 3 Equivalent Margin Analysis for 70 EFPY BWR/2-6 Weld		
ISP Surveillance Weld (Heat 5P6756):		
%Cu	=	0.06
Unirradiated USE	=	104.4 ft-lb
1st Capsule Measured USE	=	84.4 ft-lb
1st Capsule Fluence	=	1.16E+18 n/cm^2
2nd Capsule Measured USE	=	79.3 ft-lb
2nd Capsule Fluence	=	1.94E+18 n/cm^2
3rd Capsule Measured USE	=	84.6 ft-lb
3rd Capsule Fluence	=	1.58E+18 n/cm^2
4th Capsule Measured USE	=	110.7 ft-lb
4th Capsule Fluence	=	2.93E+17 n/cm^2
1st Capsule Measured % Decrease	=	19.2 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	12.1 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	24.0 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	13.7 (RG 1.99, Rev. 2, Figure 2)
3rd Capsule Measured % Decrease	=	19.0 (Charpy Curves)
3rd Capsule RG 1.99 Predicted % Decrease	=	13.0 (RG 1.99, Rev. 2, Figure 2)
4th Capsule Measured % Decrease	=	-6.0 (Charpy Curves)
4th Capsule RG 1.99 Predicted % Decrease	=	8.8 (RG 1.99, Rev. 2, Figure 2)
(Table continued on next page)		

Table 4.2.2-6 (Continued) Unit 3 Equivalent Margin Analysis for 70 EFPY BWR/2-6 Weld		
Limiting Beltline Weld USE (Heat 37C065):		
%Cu	=	0.182
70 EFPY 1/4T Fluence	=	1.48E+18 n/cm^2
RG 1.99 Predicted % Decrease	=	21.0 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
% Decrease Limit from BWRVIP-74-A	=	39.0
Comparison of Limiting % Decrease Value to Limit:		
21.0%	**≤**	**39.0%**
Therefore, Unit 3 vessel welds are bounded by Equivalent Margin Analysis		

4.2.3 REACTOR VESSEL ADJUSTED REFERENCE TEMPERATURE (ART) ANALYSES

TLAA Description:

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the P-T limit curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2 (Reference 4.8.23), provides the methodology for determining the ART of the limiting materials. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G (Reference 4.8.7), defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) determines how much higher the vessel temperature must be raised for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + ΔRT_{NDT} + Margin. Since the ΔRT_{NDT} value is a function of 54 EFPY fluence in the current ART calculations associated with the 60-year licensed operating period, these ART analyses have been identified as TLAAs requiring evaluation for the second period of extended operation.

TLAA Evaluation:

10 CFR 50, Appendix G, requires the determination of ART values for reactor vessel beltline ferritic materials for the life of the plant. The beltline plates, axial welds, and circumferential welds are fabricated from ferritic materials. The beltline also includes the N16 Water Level Instrument (WLI) nozzles and welds, which are nickel alloy materials, thus not ferritic. The N16 nozzle penetrations have partial penetration welds, so the 1/4T location along the limiting pressure stress cross-section is located within the surrounding ferritic plate material, so it is appropriate to determine the ART value for these nozzles using the plate material properties. Therefore, the ART values for the N16 nozzles and welds have been determined using the fluence and the limiting material property values (chemistry and initial RT_{NDT}) for the surrounding ferritic plate material. The ART values computed for the N16 nozzles will be used in the development of Pressure-Temperature curves that address the applied and residual stresses in the nozzles in conjunction with the appropriate material property values resulting from 70 EFPY of neutron exposure.

As described in Section 4.2.1, 70 EFPY fluence values have been determined for PBAPS Units 2 and 3 beltline materials using the methodology specified in Regulatory Guide 1.99, Revision 2. The 1/4T fluence value for each location was derived from the inside surface (0T) fluence values based upon the fluence attenuation methods described in Regulatory Guide 1.99, Revision 2 (Reference 4.8.23).

- Table 4.2.3-1 provides the 70 EFPY ART values computed for the beltline plates, axial welds, and circumferential welds shown in Figure 4.2.1-1 for the Unit 2 reactor vessel.

- Table 4.2.3-2 provides the 70 EFPY ART results for Unit 2 N16 WLI nozzle forgings and welds. The N16 nozzle forging and welds are nickel alloy materials, which are not ferritic. However, they are evaluated for ART using the fluence at the nozzle cutout location using the limiting material properties (chemistry and initial RT_{NDT}) from the surrounding plate material.

- Table 4.2.3-2 also provides 70 EFPY ART values for Integrated Surveillance Program (ISP) plate and weld material from BWRVIP-135, Revision 3 data for Unit 2 (Reference 4.8.23), which supersede plant-specific values where available, as required by BWR Integrated Surveillance Program procedures. It also includes 70 EFPY ART values computed for Integrated Surveillance Program weld materials from BWRVIP-135, Revision 3 (Reference 4.8.24).

- Table 4.2.3-3 provides the 70 EFPY ART results for Unit 3 beltline plates, axial welds, and circumferential welds shown in Figure 4.2.1-2 for the Unit 3 vessel.

- Table 4.2.3-4 provides the 70 EFPY ART results for Unit 3 N16 WLI nozzles and welds. The N16 nozzle forging and welds are nickel alloy materials, which are not ferritic. However, they are evaluated for ART using the fluence at the nozzle cutout location using the limiting material properties (chemistry and initial RT_{NDT}) from the surrounding plate material.

- Table 4.2.3-4 also provides 70 EFPY ART values for Integrated Surveillance Program (ISP) plate and weld material from BWRVIP-135, Revision 3 data for Unit 3 (Reference 4.8.23), which supersede plant-specific values where available, as required by BWR Integrated Surveillance Program procedures. It also includes 70 EFPY ART values computed for Integrated Surveillance Program weld materials from BWRVIP-135, Revision 3 (Reference 4.8.24).

The limiting locations are listed below.

Unit 2 ART Results:

- The limiting ART value for the Unit 2 reactor vessel at 70 EFPY is 70.0ºF, which was computed for Lower-Intermediate Shell plate heat C2873-1.

- The limiting ART value for the Unit 2 N16 WLI nozzle at 70 EFPY is 43.8ºF, which was computed based upon the material properties of the surrounding Lower-Intermediate Shell plate heat C2873-1 (since the nozzle forging material is nickel alloy material that does not require evaluation).

- The limiting ART value for the Unit 2 ISP plate material from BWRVIP-135, Revision 3 at 70 EFPY is 46.2ºF, computed for plate heat C2761-2.

Unit 3 ART Results:

- The limiting ART value for Unit 3 reactor vessel at 70 EFPY is 96.0ºF, computed for Lower-Intermediate Shell plate heat C2773-2.

- The limiting ART value for the Unit 3 N16 WLI nozzle at 70 EFPY is 58.6ºF, which was computed based upon the material properties of the surrounding Intermediate shell plate heat C4689-1 (since the nozzle forging material is nickel alloy material that does not require evaluation).

- The limiting ART value for the Unit 3 ISP plate material from BWRVIP-135, Revision 3 at 70 EFPY is 99.6ºF, computed for plate heat B0673-1.

The above ART values of the limiting beltline locations at 70 EFPY remain below 200°F, which is the Nil-Ductility Transition (RT_{NDT}) limit specified in NRC Regulatory Guide 1.99, Revision 2, Section 3.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The 70 EFPY reactor vessel ART analyses have been satisfactorily projected through the second period of extended operation.

Table 4.2.3-1
PBAPS Unit 2 - 70 EFPY Adjusted Reference Temperature (ART) Values for Beltline Plates and Welds

Beltline I.D.	Heat No.	Lot No.	% Cu	% Ni	CF	Initial RT_{NDT} (ºF)	70 EFPY 1/4T Fluence (n/cm^2)	ΔRT_{NDT} (ºF)	Sigma-i	Sigma-Δ	Margin (ºF)	70 EFPY Shift (ºF)	70 EFPY 1/4T ART (ºF)
Unit 2 Lower Shell Plates:													
Mark 57	C2791-2	N/A	0.12	0.52	81.4	-8	1.16E+18	36.5	0	17.0	34.0	70.5	62.5
Mark 57	C2761-1	N/A	0.11	0.54	73.4	-14	1.16E+18	32.9	0	16.4	32.9	65.7	51.7
Mark 57	C2873-2	N/A	0.12	0.57	82.4	-20	1.16E+18	36.9	0	17.0	34.0	70.9	50.9
Unit 2 Lower-Intermediate Shell Plates:													
Mark 58	C2894-2	N/A	0.13	0.42	85.6	-20	1.54E+18	43.6	0	17.0	34.0	77.6	57.6
Mark 58	C2873-1	N/A	0.12	0.57	82.4	-6	1.54E+18	42.0	0	17.0	34.0	76.0	70.0
Mark 58	C2761-2	N/A	0.11	0.54	73.4	-20	1.54E+18	37.4	0	17.0	34.0	71.4	51.4
Unit 2 Lower Shell Axial Welds:													
B1, B2, & B3	37C065	N/A	0.182	0.181	94.5	-45	1.16E+18	42.3	16	21.2	53.1	95.4	50.4
Unit 2 Lower-Intermediate Shell Axial Welds:													
C1, C2, & C3	37C065	N/A	0.182	0.181	94.5	-45	1.54E+18	48.1	16	24.1	57.8	105.9	60.9
Unit 2 Lower-to-Intermediate Shell Circumferential Weld:													
BC	S-3986	Linde 124 3876	0.056	0.96	76.4	-32	1.16E+18	34.2	0	17.1	34.2	68.4	36.4

Table 4.2.3-2
PBAPS Unit 2 - 70 EFPY Adjusted Reference Temperature (ART) Values for Beltline Nozzles and Welds and Integrated Surveillance Program Plates and Welds

Beltline I.D.	Heat No.	Lot No.	Cu	Ni	CF	Initial RT_{NDT}	70 EFPY 1/4T Fluence n/cm^2	Δ RT_{NDT}	Sigma-i	Sigma-Δ	Margin ºF	70 EFPY Shift ºF	70 EFPY 1/4T ART ºF
Unit 2 N16 Water Level Instrumentation Nozzle (WLI) Locations in Middle Shell Plates:													
N16 **[1]**	C2873-1	N/A	0.12	0.57	82.4	-6	5.30E+17	24.9	0	12.4	24.9	49.8	43.8
Unit 2 Best-Estimate Chemistry Values from BWRVIP-135 Revision 3:													
Weld BC	S-3986	N/A	0.058	0.949	79.2	-32	1.16E+18	35.5	0	17.0	34.0	69.5	37.5
Unit 2 Integrated Surveillance Program Chemistry Values from BWRVIP-135 Revision 3:													
Plate **[2]**	C2761-2	N/A	0.10	0.54	65.0	-20	1.54E+18	33.1	0	16.6	33.1	66.2	46.2
Weld **[3]**	PB2 ESW	N/A	0.10	0.32	84.2	-45	1.54E+18	42.9	0	21.4	42.9	85.8	40.8

NOTES:
Note 1: The N16 Water Level Instrumentation (WLI) nozzle is located within the beltline region of the reactor vessel. Since the forging is fabricated from Nickel Alloy 600 material, which is not ferritic, the ART value is calculated using the material properties from the surrounding plate material and the fluence value at the location of the nozzle. The weld connecting the nozzle forging to the reactor vessel shell is also fabricated from Nickel Alloy 600 material and since it is not ferritic, it does not require evaluation.
Note 2: The ISP plate material is not the vessel target material but is present within the Lower-Intermediate shell of the Unit 2 reactor vessel. Therefore, this material is considered in determining the limiting ART value. Only one set of surveillance data is currently available; therefore, upon testing of a second ISP capsule (scheduled for 2018), the CF will be reviewed and updated if necessary.
Note 3: The ISP weld material is not the vessel target material and is not present within the beltline region of the Unit 2 reactor vessel. Therefore, this material is not considered in determining the limiting ART value. The CF for the ISP material is determined using RG 1.99, Revision 2 tables using the ISP chemistry values.

Table 4.2.3-3
PBAPS Unit 3 - 70 EFPY Adjusted Reference Temperature (ART) Values for Beltline Plates and Welds

Beltline I.D.	Heat No.	Lot No.	% Cu	% Ni	CF	Initial RT_{NDT}	70 EFPY 1/4T Fluence	ΔRT_{NDT} ºF	Sigma-i	Sigma-Δ	Margin ºF	70 EFPY Shift ºF	70 EFPY 1/4T ART ºF
Unit 3 Lower Shell Plates:													
6-146-1	C4689-2	N/A	0.12	0.56	82.2	-10	8.79E+17	32.2	0	16.1	32.2	64.4	54.4
6-146-3	C4684-2	N/A	0.13	0.58	90.4	-20	8.79E+17	35.4	0	17.0	34.0	69.4	49.4
6-146-7	C4627-1	N/A	0.12	0.57	82.4	-20	8.79E+17	32.3	0	16.1	32.3	64.5	44.5
Unit 3 Lower-Intermediate Shell Plates:													
6-139-10	C2773-2	N/A	0.15	0.49	104.0	10	1.48E+18	52.0	0	17.0	34.0	86.0	96.0
6-139-11	C2775-1	N/A	0.13	0.46	86.8	10	1.48E+18	43.4	0	17.0	34.0	77.4	87.4
6-139-12	C3103-1	N/A	0.14	0.60	100.0	10	1.48E+18	50.0	0	17.0	34.0	84.0	94.0
Unit 3 Intermediate Shell Plates:													
6-146-5	C4608-1	N/A	0.12	0.55	82.0	10	9.14E+17	32.7	0	16.4	32.7	65.5	75.5
6-146-4	C4689-1	N/A	0.12	0.56	82.2	10	9.14E+17	32.8	0	16.4	32.8	65.6	75.6
6-146-2	C4654-1	N/A	0.11	0.55	73.5	10	9.14E+17	29.3	0	14.7	29.3	58.7	68.7
Unit 3 Lower Shell Axial Welds:													
D1, D2, & D3	37C065	N/A	0.182	0.181	94.5	-45	8.79E+17	37.0	16	18.5	48.9	85.9	40.9
Unit 3 Lower-Intermediate Shell Axial Welds:													
E1, E2, & E3	37C065	N/A	0.182	0.181	94.5	-45	1.48E+18	47.3	16	23.6	57.1	104.3	59.3

Table 4.2.3-3
PBAPS Unit 3 - 70 EFPY Adjusted Reference Temperature (ART) Values for Beltline Plates and Welds

Beltline I.D.	Heat No.	Lot No.	% Cu	% Ni	CF	Initial RT_{NDT}	70 EFPY 1/4T Fluence	ΔRT_{NDT} ºF	Sigma-i	Sigma-Δ	Margin ºF	70 EFPY Shift ºF	70 EFPY 1/4T ART ºF
Unit 3 Intermediate Shell Axial Welds:													
F1, F2, & F3	37C065	N/A	0.182	0.181	94.5	-45	9.14E+17	37.7	16	18.9	49.5	87.2	42.2
Unit 3 Lower Shell-to-Lower-Intermediate Shell Circumferential Weld:													
DE	3P4000	Linde 124 3932	0.020	0.934	27.0	-50	8.79E+17	10.6	0	5.3	10.6	21.1	-28.9
Unit 3 Lower Intermediate Shell-to-Intermediate Shell Circumferential Weld:													
EF	1P4217	Linde 124 3929	0.102	0.942	136.9	-50	9.14E+17	54.6	0	27.3	54.6	109.3	59.3

Table 4.2.3-4
PBAPS Unit 3 - 70 EFPY Adjusted Reference Temperature (ART) Values for Beltline Nozzles and Welds and Integrated Surveillance Program Plates and Welds

Beltline I.D.	Heat No.	Lot No.	Cu	Ni	CF	Initial RT_{NDT}	70 EFPY 1/4T Fluence n/cm^2	Δ RT_{NDT}	Sigma-i	Sigma-Δ	Margin ºF	70 EFPY Shift ºF	70 EFPY 1/4T ART ºF
Unit 3 N16 Nozzle Location in Lower-Intermediate Shell Plates:													
N16 **[1]**	C4689-1	N/A	0.12	0.56	82.2	10	5.09E+17	24.3	0	12.1	24.3	48.6	58.6
Unit 3 Best-Estimate Chemistry Values from BWRVIP-135 Revision 3:													
Weld DE	3P4000	N/A	0.020	0.935	27.0	-50	8.79E+17	10.6	0	5.3	10.6	21.1	-28.9
Weld EF	1P4217	N/A	0.104	0.938	139.3	-50	9.14E+17	55.6	0	27.8	55.6	111.2	61.2
Unit 3 Integrated Surveillance Program (ISP) Chemistry Values from BWRVIP-135 Revision 3:													
Plate **[2]**	B0673-1	N/A	0.15	0.65	111.25	10	1.48E+18	55.6	0	17.0	34.0	89.6	99.6
Weld **[3,4]**	5P6756	N/A	0.08	0.94	108.0	-45	1.48E+18	54.0	0	27.0	54.0	108.0	63.0

NOTES:
Note 1: The N16 Water Level Instrumentation (WLI) nozzle is located within the beltline region of the reactor vessel. Since the forging is fabricated from Nickel Alloy 600 material, which is not ferritic, the ART value is calculated using the material properties from the surrounding plate material and the fluence value at the location of the nozzle. The weld connecting the nozzle forging to the reactor vessel shell is also fabricated from Nickel Alloy 600 material and since it is not ferritic, it does not require evaluation.
Note 2: The ISP plate material is not the vessel target material and is not present within the beltline region of the Unit 3 reactor vessel. Therefore, this material is not considered in determining the limiting ART value. The CF for the ISP material is determined using RG 1.99, Revision 2 tables using the ISP chemistry values.
Note 3: The ISP weld material is not the vessel target material and is not present within the beltline region of the Unit 3 reactor vessel. Therefore, this material is not considered in determining the limiting ART value. The CF for the ISP material is determined using RG 1.99, Revision 2 tables using the ISP chemistry values.
Note 4: The ISP best-estimate chemistry is used.

4.2.4 REACTOR VESSEL PRESSURE-TEMPERATURE (P-T) LIMITS

TLAA Description:

10 CFR 50 Appendix G requires that the reactor pressure vessel be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the reactor pressure vessel is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated reactor vessel fluence.

The currently licensed Pressure-Temperature (P-T) limit curves are located in the Pressure-Temperature Limits Report. The currently licensed P-T curves were developed for up to 54 EFPY at the EPU power level of 3951 MWt. The 54 EFPY MUR analyses resulted in a minor increase in adjusted reference temperature (ART) of less than 0.5°F at a few beltline locations. These minor increases slightly exceed a few of the ART values assumed for the currently licensed P-T curves. Therefore, currently licensed P-T curves have been evaluated for MUR conditions and concluded to be valid for up to 53 EFPY at the MUR power level of 4016 MWt (Reference 4.8.57). Since the P-T curves are based on 53 EFPY projections for the currently approved 60-year operating term, the P-T limit curves have been identified as TLAAs requiring evaluation for the second period of extended operation.

TLAA Evaluation:

In accordance with NUREG-2192 (Reference 4.8.2), Section 4.2.2.1.4, for plants that have approved pressure-temperature limit reports (PTLR), the P-T limits for the second period of extended operation will be updated at the appropriate time through the plant's Administrative Section of the PBAPS Technical Specification 5.6.7, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)" and the plant's PTLR process. This process will ensure that the P-T limits for the second period of extended operation will be updated prior to expiration of the 53 EFPY P-T limit curves. The analyses supporting the P-T curves will consider all locations within the reactor coolant pressure boundary as they do in the current P-T curves. Maintenance of the P-T limits during the second period of extended operation will be managed using the PTLR process as described above.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) of the reactor vessels will be adequately managed through the second period of extended operation, as described in Technical Specification 5.6.7.

4.2.5 REACTOR VESSEL CIRCUMFERENTIAL WELD FAILURE PROBABILITY ANALYSES

TLAA Description:

PBAPS has previously applied for and been granted relief from RPV circumferential weld inspection for the Unit 2 vessel and for the Unit 3 vessel, as described in the NRC Safety Evaluation dated January 24, 2012 for Relief Request 14R-51 (Reference 4.8.27).

The BWRVIP recommendations for inspection of reactor pressure vessel shell welds in BWRVIP-05 (Reference 4.8.28) 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. Generic Letter 98-05 (Reference 4.8.30) informed BWR licensees that they may request such relief from the requirement to inspect circumferential wells 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 4.8.29) that evaluated BWRVIP-05. The weld failure frequency is dependent upon given assumptions of flaw density, distribution, and location. Since the current circumferential weld failure probability analyses for PBAPS Units 2 and 3, that were included in 2011 relief request 14R-51 (Reference 4.8.27), is based upon 54 EFPY 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 NRC analysis provided in “Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report” (Reference 4.8.29) computed a circumferential weld failure probability of 1.78E-05 for a vessel fabricated by CB&I at 64 EFPY, which was deemed acceptable in comparison to the axial weld probability of failure for the same vessel that is an order of magnitude higher.

In order to evaluate the PBAPS Units 2 and 3 circumferential weld failure probability for 80 years, 70 EFPY fluence values have been projected for each circumferential weld, as described in Section 4.2.1.1. Using the inside surface (0T) fluence values for these welds, the PBAPS Mean RT_{NDT} values have been determined for the circumferential welds within the beltline for each Unit. Unit 2 has one circumferential weld within the beltline (Weld BC) and Unit 3 has two (Welds DE and EF).

Table 4.2.5-1 and 4.2.5-2 provide comparisons between the NRC circumferential weld probability analysis at 64 EFPY and the PBAPS Unit 2 and Unit 3 analyses at 70 EFPY. Since the Unit 2 Mean RT_{NDT} value of 9.9ºF (Weld BC) at 70 EFPY is less than the NRC value of 70.6ºF for the CB&I vessel at 64 EFPY, the Unit 2 conditional failure probability is bounded by the NRC failure probability of 1.78E-05, consistent with the requirements defined in GL 98-05. Likewise, since the Unit 3 Mean RT_{NDT} values of (-)37.4ºF (Weld DE) and 16.1ºF (Weld EF) at 70 EFPY analyses are less than the NRC value of 70.6ºF for the CB&I vessel at 64 EFPY, the Unit 3 conditional failure probability is bounded by the NRC failure probability of 1.78E-05.

Reapplication for relief from circumferential weld examination will be made in accordance with 10 CFR 50.55a(a)(3) for NRC review and approval prior to and during the second period of extended operation. The plant-specific information described above demonstrates that at the end of the second period of extended operation, the circumferential beltline weld materials meet the limiting conditional failure probability for circumferential welds specified in the NRC’s Final Safety Evaluation Report of BWRVIP-05.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The Unit 2 and Unit 3 reactor vessel circumferential weld failure probability analyses have been projected through the second period of extended operation. Relief from inspection of circumferential welds during the second period of extended operation will be requested through a reapplication under the 10 CFR 50.55a process.

Table 4.2.5-1 PBAPS Unit 2 Circumferential Weld Probability Analyses		
Parameter	**NRC Staff Analysis for 64 EFPY (Circumferential Welds) [1]**	**PBAPS Unit 2 Analysis for 70 EFPY (Circumferential Weld BC)**
Copper Content (%)	0.10	0.058
Nickel Content (%)	0.99	0.949
Chemistry Factor (CF)	134.9	79.2 **[3]**
Fluence at 0T (n/cm^2)	1.02E+19	1.68E+18
Unirradiated Reference Temperature $RT_{NDT(U)}$ (ºF)	-65	-32
Shift in Reference Temperature ΔRT_{NDT} (ºF) (without margin) **[2]**	135.6	41.9
Mean RT_{NDT} (ºF)	70.6	9.9
Conditional Failure Probability	1.78E-05	**[4]**

NOTES:
Note 1: The NRC data is obtained from Table 2.6-5 of BWRVIP-05 Report, "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, July 28, 1998 (Reference 4.8.29), with corrected Chemistry Factor from the Supplement to the Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, March 7, 2000.
Note 2: $\Delta RT_{NDT} = CF * f^{(0.28 - 0.10 \log f)}$, where "f" is fluence in units of E+19 n/cm^2.
Note 3: Best-estimate chemistry values for circumferential weld BC were used for conservatism.
Note 4: Since the PBAPS Unit 2 Mean RT_{NDT} values are significantly less than the NRC values, it is concluded that the PBAPS Unit 2 conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05.

Table 4.2.5-2 PBAPS Unit 3 Circumferential Weld Probability Analysis			
Parameter	**NRC Staff 64 EFPY (Circumferential Weld) [1]**	**Unit 3 70 EFPY (Circumferential Weld DE)**	**Unit 3 70 EFPY (Circumferential Weld EF)**
Copper Content (%)	0.10	0.020	0.104
Nickel Content (%)	0.99	0.935	0.938
Chemistry Factor (CF)	134.9	27.0 **[3]**	139.3 **[3]**
Fluence at 0T (n/cm^2)	1.02E+19	1.27E+18	1.32E+18
Unirradiated Reference Temperature $RT_{NDT(U)}$ (ºF)	-65	-50	-50
Shift in Reference Temperature ΔRT_{NDT} (ºF) (without margin) **[2]**	135.6	12.6	66.1
Mean RT_{NDT} (ºF)	70.6	-37.4	16.1
Conditional Failure Probability	1.78E-05	**[4]**	**[4]**

NOTES:
Note 1: The NRC data is obtained from Table 2.6-5 of BWRVIP-05 Report, "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, July 28, 1998 (Reference 4.8.29), with corrected Chemistry Factor from the Supplement to the Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, March 7, 2000.
Note 2: $\Delta RT_{NDT} = CF * f^{(0.28 - 0.10 \log f)}$, where "f" is fluence in units of E+19 n/cm^2.
Note 3: Best-estimate chemistry values were used for conservatism.
Note 4: Since the PBAPS Unit 3 Mean RT_{NDT} values are significantly less than the NRC values, it is concluded that the PBAPS Unit 3 conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05.

4.2.6 REACTOR VESSEL AXIAL WELD FAILURE PROBABILITY ANALYSES

TLAA Description:

The BWRVIP recommendations for inspection of reactor pressure vessel shell welds in BWRVIP-05 (Reference 4.8.28) 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.

Subsequent to the original SER for BWRVIP-05, additional failure probability analyses were performed by the BWRVIP to more accurately determine the conditional failure probability of BWR axial welds. The Staff reviewed these and provided separate conditional failure probability analyses in the Supplement to the Final Safety Evaluation of the BWRVIP-05 Report, dated March 7, 2000 (Reference 4.8.31). These analyses resulted in higher failure probabilities than the BWRVIP analyses and are therefore limiting. They demonstrate that the RPV failure frequency due to failure of the axial welds in the BWR fleet are no greater than 5.02E-06 per reactor year. The weld failure frequency is dependent upon given assumptions of flaw density, distribution, and location. Since the current axial weld failure probability analyses for PBAPS Units 2 and 3 that were included in the February 2017 MUR amendment submittal (Reference 4.8.57) are based upon 54 EFPY 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 NRC analysis provided in Table 3 of the Supplement to the Final Safety Evaluation of the BWRVIP-05 Report, dated March 7, 2000 (Reference 4.8.31) computed a RPV failure frequency of 5.02E-06 due to failure of limiting axial welds in the BWR fleet. In order to evaluate axial weld failure probability analyses for 80 years for the PBAPS Unit 2 and Unit 3 vessels, 70 EFPY fluence projections have been developed for the inside surface (0T) of the limiting axial welds using the GEH DORT fluence methodology, as described in Section 4.2.1.1. Using the bounding inside surface fluence value, the mean RT_{NDT} values have been determined for these welds, where the mean RT_{NDT} value does not include the margin term (M) described in RG 1.99, Revision 2, consistent with the evaluation methodology described in Section 2.1 of the March 7, 2000 supplement to the final safety evaluation (Reference 4.8.31). The results are shown in SLRA Table 4.2.6-1 for Unit 2 and Table 4.2.6-2 for Unit 3.

SLRA Table 4.2.6-1 provides a comparison of the limiting Unit 2 axial weld mean RT_{NDT} value at 70 EFPY (without margin) to the mean RT_{NDT} value (without margin) determined for the limiting reactor in the March 7, 2000 supplement to the final safety evaluation. Since the mean RT_{NDT} value of 114ºF from the Staff analysis bounds the limiting Unit 2 mean RT_{NDT} value of 11.3ºF, the Staff failure probability of 5.02E-06 is bounding for the Unit 2 axial welds at 70 EFPY.

SLRA Table 4.2.6-2 provides a comparison of the limiting Unit 3 axial weld mean RT_{NDT} value at 70 EFPY (without margin) to the mean RT_{NDT} value (without margin) determined for the limiting reactor in the March 7, 2000 supplement to the final safety evaluation. Since the mean RT_{NDT} value of 114ºF from the Staff analysis bounds the limiting Unit 3 mean RT_{NDT} value of 10.4ºF, the Staff failure probability of 5.02E-06 is bounding for the Unit 3 axial welds at 70 EFPY.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The Unit 2 and Unit 3 reactor vessel axial weld failure probability analyses have been satisfactorily projected through the second period of extended operation.

Table 4.2.6-1
PBAPS Unit 2 Axial Weld Failure Probability Analyses

Parameter	NRC Staff Analysis for 32 EFPY Mod 2 Variant (Axial Welds) [1]	PBAPS Unit 2 Analysis for 70 EFPY (Axial Weld 37C065)
Copper Content (%)	0.219	0.182
Nickel Content (%)	0.996	0.181
Chemistry Factor (CF)	231.1	94.5
Fluence at 0T (n/cm^2)	1.48E+18	2.23E+18 **[4]**
Unirradiated Reference Temperature $RT_{NDT(U)}$ (°F)	-2	-45
Shift in Reference Temperature ΔRT_{NDT} (°F) (without margin) **[2]**	116	56.3
Mean RT_{NDT} (°F)	114	11.3
Vessel Failure Frequency	5.02E-06	**[3]**

NOTES:
Note 1: The NRC data is obtained from the Supplemental Safety Evaluation of BWRVIP-05 Report, March 7, 2000 (Reference 4.8.31).
Note 2: $\Delta RT_{NDT} = CF * f^{(0.28 - 0.10 \log f)}$, where f is fluence in units of E+19 n/cm^2.
Note 3: Since the PBAPS Unit 2 Mean RT_{NDT} value of 11.3°F is less than the NRC value of 114°F, it is concluded that the PBAPS Unit 2 conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05.
Note 4: Beltline axial welds are the same heat (37C065). The bounding 70 EFPY fluence value for axial welds is used in this analysis.

Table 4.2.6-2
PBAPS Unit 3 Axial Weld Failure Probability Analyses

Parameter	**NRC Staff Analysis for 32 EFPY Mod 2 Variant (Axial Welds) [1]**	**PBAPS Unit 3 Analysis for 70 EFPY (Axial Weld 37C065) [3]**
Copper Content (%)	0.219	0.182
Nickel Content (%)	0.996	0.181
Chemistry Factor (CF)	231.1	94.5
Fluence at 0T (n/cm^2)	1.48E+18	2.14E+18 [4]
Unirradiated Reference Temperature $RT_{NDT(U)}$ (ºF)	-2	-45
Shift in Reference Temperature ΔRT_{NDT} (ºF) (without margin) **[2]**	116	55.4
Mean RT_{NDT} (ºF)	114	10.4
Vessel Failure Frequency	5.02E-06	**[3]**

NOTES:
Note 1: The NRC data is obtained from the Supplemental Safety Evaluation of BWRVIP-05 Report, March 7, 2000 (Reference 4.8.31).
Note 2: $\Delta RT_{NDT} = CF * f^{(0.28 - 0.10 \log f)}$, where f is fluence in units of E+19 n/cm^2.
Note 3: Since the PBAPS Unit 3 Mean RT_{NDT} value of 10.4ºF is significantly less than the NRC value of 114ºF, it is concluded that the PBAPS Unit 3 conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05.
Note 4: Beltline axial welds are the same heat (37C065). The bounding 70 EFPY fluence value for axial welds is used in this analysis.

4.2.7 REACTOR VESSEL REFLOOD THERMAL SHOCK ANALYSIS

TLAA Description:

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 Boiling Water Reactors (BWR) designed by General Electric (GE), this requirement was demonstrated both by development of Pressure-Temperature Limit Curves, which are addressed in SLRA Section 4.2.4, and by reference to a generic fracture mechanics analysis (Reference 4.8.32) prepared in 1979 that evaluates the effects of the limiting Loss of Coolant Accident (LOCA) event. The MUR amendment submittal for PBAPS Units 2 and 3, February 2017 also evaluated RPV reflood thermal shock for 54 EFPY (Reference 4.8.57). For clarity, the 1979 analysis will be described in detail in this TLAA description section.

The purpose of the 1979 analysis was to assess the capability of General Electric BWR vessels to withstand the consequences of a design basis LOCA event without compromising the structural integrity of the vessel. In analyzing the LOCA event for a fracture evaluation, two types of pipe rupture can be postulated; (i) steam line break, or (ii) recirculation line break. Both events assume a guillotine rupture of the line when the reactor is operating at full power. Evaluation of heat transfer conditions and temperature gradients showed that the steam line break is more severe than the recirculation line break from the viewpoint of thermal stresses and brittle fracture. Therefore, the steam line break is the controlling design basis accident for the purpose of this evaluation.

Following the postulated guillotine rupture of the steam line, the reactor undergoes rapid depressurization during which two-phase flow with boiling occurs. Immediately following the break, the large increase in core void fraction due to depressurization causes a sharp reduction in reactor power and a control rod scram will be initiated in less than a second. Several Emergency Core Cooling Systems (ECCS) are activated following the break and there is rapid depressurization from 1050 psi to about 120 psi in approximately one minute. Following this, there is a more gradual depressurization to ambient pressure at approximately 300 seconds after the pipe break. During the entire LOCA event, the water level in the vessel stays well above the top of the active fuel zone. Therefore, the beltline region that is being evaluated is always surrounded by water on the inside surface.

Prior to the LOCA, the vessel wall was assumed to be in steady-state equilibrium with the reactor coolant at 550 ºF. The analysis shows that at 300 seconds into the event, the applied stress intensity factor, $K_{I\text{-applied}}$, reaches a peak value of approximately 100 ksi-in$^{1/2}$, then slowly decreases. By this 300-second point in the event, the vessel wall temperature at the 1/4T depth from the inside surface is reduced from 550ºF to approximately 400ºF.

Immediately after the accident and before the vessel coolant is subcooled by the ECCS flow, the reactor undergoes rapid depressurization. Boiling occurs at the interface between the vessel wall and the reactor coolant. As a result, the heat transfer regime is forced two-phase convection with boiling for which the heat transfer coefficient is potentially as high as 10,000 BTU/hr-ft^2 ºF.

Sometime after all ECCS systems are initiated, the coolant flow is sufficient to sub-cool the bulk liquid inventory, and the flow regime changes to forced convection of subcooled water over a metal surface, where a heat transfer coefficient of 500 BTU/hr-ft^2 ºF could be assumed. To add conservatism to the analysis, the higher heat transfer coefficient was assumed through the entire depressurization period, i.e. up to 300 seconds after the pipe break when the pressure reaches ambient conditions. After 300 seconds, the lower heat transfer coefficient was assumed for the remainder of the LOCA event.

The acceptance criterion used in this fracture mechanics analysis is that the resulting maximum applied stress intensity factor, K_I, present during the bounding Emergency or Faulted condition (Service Level C and D), which is the crack driving force for postulated flaws in the RPV, is less than the limiting material resistance to fracture, K_{Ic}, applicable during the event. Thermal analysis was performed using a finite element program and an axisymmetric finite element model. The maximum applied stress intensity factor was calculated as a function of crack depth for a postulated surface crack in the beltline region of the reactor vessel wall for the combined thermal, pressure, and residual stresses. Temperature distributions through the wall thickness at different times during the event were determined. The maximum applied thermal stress intensity factor, K_I, was determined to be 100 ksi-in$^{1/2}$ at 300 seconds after the LOCA.

The available toughness, calculated as a function of crack tip temperature and fluence level, was determined to be beyond that highest available toughness in the code curves. Therefore, the maximum value of 200 ksi-in$^{1/2}$ was assumed. This value is significantly greater than the maximum applied stress intensity factor of 100 ksi-in$^{1/2}$ at all times during the transient. It was concluded that the reactor vessel has a considerable margin to failure by brittle fracture even in the presence of large postulated initial flaws. Since the material fracture toughness exceeds the maximum applied stress intensity factor at that point in the event by a significant margin, an existing flaw in the vessel would not propagate due to brittle fracture during a LOCA.

Since the MUR amendment submittal for PBAPS Units 2 and 3, February 2017 (Reference 4.8.57) evaluated RPV reflood thermal shock for 54 EFPY over a 60-year period, this analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

TLAA Evaluation:

Updated 80-year fracture mechanics evaluations have been performed for the reflood thermal shock event using plant-specific reactor pressure vessel data for PBAPS Units 2 and 3. The limiting adjusted reference temperature (ART) values for Unit 2 and Unit 3 beltline materials, based upon 70 EFPY fluence projections, have been used in these fracture mechanics analyses. The adjusted reference temperature is the RT_{NDT} value adjusted to account for increased fluence during the life of the component.

The updated evaluations next determined if these limiting materials will have sufficient fracture toughness at 70 EFPY to resist the maximum applied stress intensity factor of 100 ksi-in$^{1/2}$ computed in the original analysis. This was done by determining the temperature at which K_{IC} of the beltline material with the limiting ART value reaches the upper shelf value of 200 ksi-in$^{1/2}$ that is the upper limit of the K_{IC} curve, as shown in Figure G-4200-1 of ASME Section XI, Appendix G (Reference 4.8.61).

> K_{IC} is defined in ASME Section XI, Appendix A-4200 as the fracture toughness associated with static crack initiation for a given material:

K_{IC} = 33.2 + 20.734 exp[0.02 (T – RT_{NDT})] (note: RT_{NDT} = ART, if the material is irradiated)

For Unit 2, by setting K_{IC} = 200 ksi-in$^{1/2}$, and using the limiting 70 EFPY Unit 2 ART value of 70.0ºF for Lower-Intermediate Shell plate heat C2873-1 (obtained from SLRA Table 4.2.3-1), the temperature, T, at which K_{IC} reaches 200 ksi-in$^{1/2}$, was determined to be 174.3ºF. This is well below approximately 400°F, which is the 1/4T temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the analysis has been satisfactorily projected through the second period of extended operation.

For Unit 3, using the limiting 70 EFPY ART value of 96ºF for Unit 3 Lower-Intermediate Shell Plate heat C2773-2 (obtained from SLRA Table 4.2.3-3), the temperature, T, at which K_{IC} reaches 200 ksi-in$^{1/2}$, was determined to be 200.3ºF. This is well below approximately 400°F, which is the 1/4T temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the analysis has been satisfactorily projected through the second period of extended operation.

Therefore, the limiting material will retain a minimum toughness of 200 ksi-in$^{1/2}$ as long as the temperature at the 1/4T location at the time of maximum applied stress intensity remains at or above 174.3ºF for Unit 2, and at or above 200.3ºF for Unit 3. Since the 1/4 T location will be at approximately 400ºF at 300 seconds into the event, the maximum applied stress intensity factor of 100 ksi-in$^{1/2}$ will be less than the fracture toughness of the material of 200 ksi-in$^{1/2}$ by a significant margin. Therefore, during the second period of extended operation for each Unit, there is sufficient toughness margin to prevent RPV fracture due to reflood thermal shock. An existing flaw in the reactor vessel would not propagate due to brittle fracture during a LOCA as a result of thermal shock.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The reactor vessel reflood thermal shock analysis has been satisfactorily projected through the second period of extended operation.

4.2.8 CORE SHROUD REFLOOD THERMAL SHOCK ANALYSIS

TLAA Description:

Neutron irradiation embrittlement may affect the ability of reactor vessel core shroud to withstand a low-pressure coolant injection thermal shock transient. The reactor vessel core shrouds were analyzed for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of 40-year neutron irradiation exposure (32 EFPY). The core shrouds receive the maximum irradiation on the inside surface approximately opposite the midpoint of the fuel centerline. PBAPS UFSAR Section 3.3.5.4 documents the maximum thermal shock stress in this region was determined to be 155,700 psi at the midpoint of the shroud, which is equivalent to 0.57 percent strain (Reference 4.8.19). This analysis was revaluated for the first license renewal project and validated for a 60-year extended operating term (Reference 4.8.58).

Since this analysis was identified as a TLAA for the first license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

This issue was previously evaluated as TLAAs during the license renewal of the Dresden and Quad Cities plants (Reference 4.8.75) and in the license renewal application of the Brown's Ferry plants (Reference 4.8.33). Similar to PBAPS, the Brown's Ferry maximum thermal shock stress in the shroud was determined to be 155,700 psi with an equivalent 0.57 percent strain. In associated RAI responses, Browns Ferry provided material destructive testing results of highly irradiated Type 304 stainless steel to demonstrate that the core shrouds would withstand a low-pressure coolant injection event. These conclusions were accepted by the Staff as documented in the associated license renewal SERs for both applications (References 4.8.33 and 4.8.75). These same material destructive testing results can be used to disposition neutron irradiation embrittlement of the PBAPS core shrouds and their ability to withstand a low-pressure coolant injection thermal shock transient.

During the Staff's review of the Brown's Ferry application, there was discussion between the applicants and the Staff regarding which material property value should be evaluated to provide the most appropriate measure of ductility to compare to the stress and strain values associated with the reflood thermal shock event. The choice was between material "reduction in area" percentage or material "elongation" percentage. These properties may be measured during tensile testing of highly irradiated Type 304 stainless steel (Reference 4.8.33). Each of these approaches is discussed below with respect to the PBAPS core shrouds.

The first material property considered is "reduction in area", since the strain associated with the reflood thermal shock event is very localized and is constrained by the surrounding bulk material. As such, it is similar to the triaxial stress condition present in the neck region (where the area reduction is taking place) during a tensile test. Since the percentage reduction in area is a measure of this triaxial stress state, it is the most appropriate property for evaluating the effect of thermal shock on the core shroud (Reference 4.8.33).

The measured percentage "reduction in area" values at failure for annealed Type 304 stainless steel test material that was provided in the Brown's Ferry response to RAI 4.2.4-1(C) (Reference 4.8.33) are shown in Table 4.2.8-1 below:

Table 4.2.8-1 Reduction in Area Values		
Fluence (n/cm^2, E>1MeV)	**Test Temperature (ºF)**	**Reduction in Area (%) at Failure**
1.0E+21	550	40
6.9E+21	750	52.5

The bounding 60-year shroud fluence for Brown's Ferry is 5.34E+21 n/cm^2. The maximum 80-year (70 EFPY) shroud weld fluence for PBAPS Unit 2 is 3.63E+21 n/cm^2 and for Unit 3 is 3.45E+21 n/cm^2. Therefore, the conclusion for the Brown's Ferry shrouds also applies to the PBAPS shrouds. Based upon the "reduction in area" evaluation approach using 70 EFPY projected fluence values, the PBAPS Unit 2 and Unit 3 core shrouds will have sufficient ductility during the reflood thermal shock transient to resist the 155,700 psi stress, which is equivalent to 0.57 percent strain, through the second period of extended operation.

The second approach for evaluating the reflood thermal shock, based on the "elongation" material property, also supports this conclusion. Table 4.2.8-2 provides the "elongation" test data that was provided in the Brown's Ferry response to RAI 4.2.4-1(C) (Reference 4.8.33) for annealed Type 304 stainless steel material exposed to 8.0E+21 n/cm^2.

Table 4.2.8-2 Elongation Values			
Material	**Fluence (n/cm^2, E>1MeV)**	**Test Temperature (ºF)**	**Elongation at Failure (%)**
Base	8E+21	554	20
Weld	8E+21	567	4

This table shows that the calculated Brown's Ferry and PBAPS maximum strain range of 0.57 percent resulting from the reflood thermal shock is well below the 4.0 percent elongation at failure measured value for annealed Type 304 stainless steel irradiated to 8.0E+21 n/cm^2, which is significantly greater than the 80-year (70 EFPY) shroud weld projected fluence values of 3.63E+21 n/cm^2 and 3.45E+21 n/cm^2 for PBAPS Units 2 and 3. Therefore the calculated thermal shock strain at the most irradiated location is acceptable considering the embrittlement effects for the PBAPS 80-year operating period.

Based upon the elongation approach using 70 EFPY projected fluence values, the PBAPS Unit 2 and Unit 3 core shrouds will have sufficient ductility during the reflood thermal shock transient to resist the 155,700 psi stress, which is equivalent to 0.57 percent strain, at the end of the second period of extended operation.

TLAA Disposition: 10CFR54.21(c)(1)(i): The reactor vessel core shroud reflood thermal shock analysis remains valid through the second period of extended operation.

4.2.9 CORE PLATE RIM HOLD-DOWN BOLT LOSS OF PRELOAD ANALYSIS

TLAA Description:

The RPV core plate is attached to the core support structure by 34 stainless steel hold-down bolts arranged along the rim of the plate. These core plate rim hold-down bolts are 2.5 inches in diameter and approximately 28.3 inches long. The bolts were preloaded during initial installation but are subject to stress relaxation (loss of preload) as a result of irradiation effects. The stress state of these bolts was evaluated as part of the analysis performed by General Electric Hitachi (GEH) to prepare BWRVIP-25 Revision 0, "BWR Vessel and Internals Project BWR Core Plate Inspection and Flaw Evaluations Guidelines" (Reference 4.8.36). The analysis determined that a 5 percent to 19 percent reduction in core plate bolt preload due to thermal and irradiation effects should be expected over the 40-year life of a plant. A subsequent reevaluation performed by GEH determined that the maximum relaxation value of 19 percent is applicable to an average fluence level of 8.0E+19 n/cm^2 over the length of the bolt, determined at the peak azimuthal fluence location. Since this analysis evaluated irradiation effects expected to occur in 40 years, this analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

TLAA Evaluation:

As described in Section 4.2.1.2, RAMA fluence projections were prepared for PBAPS Units 2 and 3 for 70 EFPY for selected reactor vessel internal components. This included fluence projections for all core plate rim hold-down bolts for each unit. These fluence projections demonstrate acceptable bolt relaxation over an 80-year period.

The total loss of preload in each bolt is a summation of the losses that occur throughout the length of the bolt, which varies as a function of fluence. Since the fluence tapers off from the top of the bolt to the bottom, due to the increased distance from the fuel, the average fluence along the length of the bolt was used in the GEH analysis to determine a fluence value of 8.0E+19 n/cm^2 associated with the 19 percent total loss of preload.

The bolts at the peak azimuthal location with the highest fluence for PBAPS Unit 2 and Unit 3 are bolt numbers 4, 15, 21, and 32, which have the same fluence values due to core symmetry. Fluence projections were made at the centerline of 27 discrete points equally spaced along the tensioned portion of these limiting bolts. For Unit 2, the 70 EFPY average fluence value of the bolts is 6.57E+19 n/cm^2. For Unit 3, the 70 EFPY average fluence value of the bolts is 6.53E+19 n/cm^2. Since these average fluence values are less than the 8.0E+19 n/cm^2 average fluence value previously evaluated in the TLAA, which resulted in an acceptable maximum relaxation value of 19 percent, the TLAA remains bounding for 70 EFPY and 80 years of operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The core plate rim hold-down bolt loss of preload analysis remains valid through the second period of extended operation.

4.2.10 JET PUMP SLIP JOINT REPAIR CLAMP LOSS OF PRELOAD ANALYSIS

TLAA Description:

Jet pump slip joint repair clamps have been designed and installed on jet pumps in PBAPS Unit 2 to minimize slip joint vibration and wear of the jet pump assemblies. Eight clamps were installed in 2004, one was installed in 2008, and two were installed in 2014. None have been installed in Unit 3. The clamps apply a lateral preload to the slip joint, between the exit end of the inlet-mixer and the entrance end of the diffuser.

The design specification for the repair clamp states that the peak neutron fluence at the slip joint is 1.115 E+20 n/cm^2 for the 40-year design life of the clamp. The specification requires the design to account for the effect of fluence on the properties of the slip joint materials for the design life of the clamp. The structural evaluation states that the "cold" bolt preload is 550 pounds at 100ºF, the initial “hot” preload at 550ºF is 500 pounds, and the minimum, end-of-life preload is 350 pounds at 550ºF. Therefore, 150 pounds is attributed for loss of preload during the life of the component, associated with a neutron fluence exposure of 1.115E+20 n/cm^2. The analysis for loss of preload due to neutron fluence has been identified as a TLAA for the jet pump slip joint clamps that requires evaluation for the second period of extended operation.

TLAA Evaluation:

In order to evaluate the clamp loss of preload TLAA, the projected fluence at clamp locations inside the reactor vessel was determined from initial clamp installation in 2004 through the end of the second period of extended operation. RAMA fluence projections were performed that specifically modeled the limiting location of the clamps installed in 2004. The peak fluence value is projected to reach of 1.17E+19 n/cm^2 at the end of the second period of extended operation. Therefore, since this value is less than the design value of 1.115E+20 n/cm^2, this TLAA has been determined to remain valid through the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i): The jet pump slip joint repair clamp design analysis for loss of preload remains valid through the second period of extended operation.

4.2.11 JET PUMP AUXILIARY SPRING WEDGE ASSEMBLY LOSS OF PRELOAD ANALYSIS

TLAA Descriptions:

The PBAPS jet pump (JP) assemblies have had auxiliary spring wedge assemblies installed to maintain lateral support for the jet pump inlet mixer. The design stress analysis considered potential aging effects, including loss of preload due to radiation effects based upon a design life of 40 years.

Auxiliary spring wedge assemblies were installed in Unit 2 on JP 10, 12, and 18 in 2004, installed on JP 14, 19, and 20 in 2006, replaced on JP 10 and JP 18 in 2014, and removed from JP 20 in 2014. Therefore, the earliest installed auxiliary spring wedge assembly will have a maximum in-service time of approximately 49 years at the end of the second period of extended operation in August 2053.

An auxiliary spring wedge assembly was installed in Unit 3 on JP 14 in 2001 and will have a maximum in-service time of approximately 53 years at the end of the second period of extended operation in July 2054. An auxiliary spring wedge assembly was installed in Unit 3 on JP 09 in 2001 and removed during the 2017 refueling outage.

The auxiliary spring wedge assembly design analysis determined that the fluence levels in the regions where the auxiliary wedges are installed on the jet pumps are less than 5.0E+20 n/cm^2 for a 40-year design life. An assumed 10 percent load relaxation was used in the analysis to account for loss of preload due to thermal and radiation effects. The analysis for loss of preload due to neutron fluence has been identified as a TLAA for the auxiliary spring wedge assemblies, that requires evaluation for the second period of extended operation.

TLAA Evaluation:

To evaluate loss of preload for the second period of extended operation, RAMA fluence projections were developed for the bounding auxiliary spring wedge assembly locations in each unit.

For Unit 2, the maximum fluence at the limiting auxiliary spring wedge assembly was determined to be 1.53E+20 n/cm^2 for the first installed auxiliary spring wedge assembly installed in 2004 to the end of the second period of extended operation. For Unit 3, the maximum fluence at the limiting auxiliary spring wedge assembly is 8.12E+18 n/cm^2 for the first installed auxiliary spring wedge assembly installed in 2001 to the end of the second period of extended operation. Each of these projected fluence values are less than the 5.0E+20 n/cm^2 fluence value assumed in the design structural analysis for which the 10 percent loss of preload allowance was applied. Therefore, the design stress analysis remains valid through the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i): The jet pump auxiliary spring wedge assembly design stress analysis for loss of preload remains valid through the second period of extended operation.

4.2.12 JET PUMP RISER REPAIR CLAMP LOSS OF PRELOAD ANALYSIS

TLAA Description:

During the fall 1997 refueling outage for Unit 3, crack indications were detected in the heat-affected zones of the jet pump riser elbow-to-thermal sleeve welds for Jet Pump numbers 01/02 and 13/14. A mechanical clamping system designed to structurally replace these welds was installed on both jet pump risers in 1998. Since these clamshell-style clamps use bolts to maintain the proper clamping force, loss of preload due to neutron irradiation stress relaxation was a design consideration. The design specification assumed that the neutron fluence at the riser pipe clamp location would not exceed 2.5E+19 n/cm^2 during the 17-year planned service life of the clamp. Since the neutron fluence value was assumed through the end of the initial 40 years of operation, the design analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

TLAA Evaluation:

In order to determine if this fluence assumption will remain valid through 80 years of operation, the neutron fluence was projected for 70 EFPY using the RAMA fluence methodology previously described in Section 4.2.1.2. The 70 EFPY fluence value at the limiting Unit 3 jet pump riser clamp location was determined to be 5.29E+15 n/cm^2, which is less than the 2.5E+19 n/cm^2 fluence value assumed in the design specification for the clamp. Therefore, the riser clamp design analysis for loss of preload, based upon the design specification, remains valid through the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The analysis for jet pump riser repair clamp loss of preload remains valid through the second period of extended operation.

4.2.13 REPLACEMENT CORE PLATE EXTENDED LIFE PLUG IRRADIATION-ENHANCED STRESS RELAXATION ANALYSIS

TLAA Description:

The original design of the Peach Bottom Units 2 and 3 core plates included holes for bypass flow. It was discovered that the flow through the holes produced high velocity jets that impinged on the in-core instrument tubes which subjected them to high levels of flow induced vibration which led to wear on the adjacent fuel channels. The core plate holes were plugged to prevent the unwanted flow induced vibration. During the PBAPS, Unit 3 fall 2001 refueling outage, all 129 reactor core plate plugs were replaced with extended life core support plugs. During the PBAPS, Unit 2 fall spring 2012 refueling outage, all 129 reactor core plate plugs were replaced with extended life plugs. The extended life core support plugs have a service life of 35 EFPY corresponding to a fluence of 5.25E+20 n/cm^2. Due to the effects of irradiation-enhanced stress relaxation, the amount of force applied by the plug mandrel spring is dependent on the accumulated neutron fluence. The plug mandrel spring essentially holds the extended life core support plug, tight in the core plate, against a force of 46.7 pounds created by the differential pressure across the core plate. Therefore, irradiation-enhanced stress relaxation of the mandrel spring due to neutron irradiation has been identified as a TLAA and must be evaluated for an additional 20 EFPY, which corresponds to the second period of extended operation.

TLAA Evaluation:

Reevaluation of the service life of the extended life core support plugs concludes that the service life can be extended by an additional 20 EFPY for total service life of 55 EFPY. The reevaluation concluded that at the end of the 55 EFPY period the core support plug mandrel springs are estimated to experience fluence values of 8.25E+20 n/cm^2 with a resulting end of life mandrel spring preload of 111 pounds which exceeds the force acting on the plug due to the differential pressure, by margin of at least 100 percent. Therefore, the extended life core support plugs will not reach the end of their service life until 2067 for Unit 2 and 2056 for Unit 3, assuming an operating capacity factor of 100 percent. Since the second period of extended operation will end in 2053 for Unit 2 and 2054 for Unit 3 the new service life of 55 EFPY will not be exceeded during the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The analysis for core plate plug irradiation-enhanced stress relaxation has been satisfactorily projected through the second period of extended operation.

4.2.14 FIRST LICENSE RENEWAL APPLICATION CORE SHROUD IASCC AND EMBRITTLEMENT ANALYSIS

TLAA Description:

Section 4.3.2.2 of the first PBAPS License Renewal Application (LRA) presents a fluence threshold value of 5.0E+20 n/cm^2 beyond which IASCC and embrittlement may occur in BWR vessel internal components. Section 4.3.2.2 of the first PBAPS LRA concludes that the expected fluence on the inner surfaces of the core shroud would be 4.5E+20 n/cm^2 at the end of the 60-year first period of extended operation. Therefore, aging management of the core shroud is not required through the first period of extended operation. Since the core shroud analysis presented in Section 4.3.2.2 of the first PBAPS LRA determined that IASCC and embrittlement were not applicable aging effects expected to occur in 60-years, this analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

The top guide was also addressed in Section 4.3.2.2 of the first PBAPS LRA, but the generic 60-year fluence on the top guide was above the threshold, and in response to and addressed under Open Item 4.5.2-1, the aging effects of IASCC and embrittlement were addressed by an inspection program.

TLAA Evaluation:

Fluence values for the PBAPS Unit 2 and Unit 3 core shroud and top guide are projected to exceed the threshold of 5.0E+20 n/cm^2 before the end of the second period of extended operation. Therefore, the core shroud and top guide will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the second period of extended operation in accordance with the BWR Vessel Internals (B.2.1.7) aging management program.

For periodic core shroud inspections, the BWR Vessel Internals aging management program utilizes the recommendations in provided in BWRVIP-76-R1-A “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines.” For periodic top guide inspections, the BWR Vessel Internals aging management program utilizes the recommendations in provided BWRVIP-26-A “BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines” and BWRVIP-183 “BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines.”

Therefore, aging effects of IASCC and embrittlement on the core shroud and top guide will be managed in the second period of extended operation in accordance with the BWR Vessel Internals (B.2.1.7) aging management program.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – Aging effects of IASCC and embrittlement on the reactor vessel core shroud will be managed by the BWR Vessel Internals (B.2.1.7) aging management program through the second period of extended operation.

4.2.15 UNIT 3 CORE SPRAY REPLACEMENT PIPING BOLTING LOSS OF PRELOAD EVALUATION

TLAA Description:

In 2013, portions of the Core Spray System piping segment located inside the reactor vessel were replaced on Unit 3 from the thermal sleeves in reactor pressure vessel nozzles N5A and N5B to the shroud wall.

A design report associated with this replacement evaluated loss of preload due to fluence on the most limiting bolting component. The loss of preload evaluation projected a fluence value of 3.6E+19 n/cm^2 over a 40-year service life. This resulted in a reduction of preload to 3,775 pounds at the end of the 40-year period, which exceeds and meets the acceptance criterion of 3,504 pounds.

Since the design report evaluated the effects of fluence on loss of preload over a 40-year service life, until 2053, the evaluation has been identified as a TLAA that requires evaluation for the second period of extended operation, which ends in 2054 for PBAPS Unit 3.

TLAA Evaluation:

The associated loss of preload evaluation was reevaluated by GEH for an additional five years of service life for a total of 45 years, until 2058. The reevaluation applied a projected fluence value of 4.1E+19 n/cm^2 over 45 years at the location of the most limiting bolting component. This resulted in a reduction of preload on the most limiting bolting component to 3,682 pounds through 2058, which exceeds and meets the acceptance criterion of 3,504 pounds.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) - The Unit 3 replacement core spray piping bolting loss of preload evaluation has been satisfactorily projected through the second period of extended operation.

4.3 METAL FATIGUE ANALYSES

Fatigue analyses are required on components designed to ASME, Section III, Class 1 and Class MC. In addition, certain other codes such as ASME Section III, Class 2 and 3, USAS (ANSI) B31.1, and ASME Section VIII Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. As described in SLRA Section 4.1, NUREG-2192 also provides examples of components that are likely to have fatigue TLAAs within the current licensing basis that would require evaluation for the second period of extended operation. Searches were performed to identify these and any other potential fatigue TLAAs within the current licensing bases for PBAPS Units 2 and 3. Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as PBAPS fatigue TLAAs are evaluated using 80-year transient cycle and cumulative usage projections, described is Section 4.3.1, and summarized in the following subsections:

- ASME Section III, Class 1 Fatigue Analyses (Section 4.3.2)
- ASME Section III, Class 1 Fatigue Waivers (Section 4.3.3)
- ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses (Section 4.3.4)
- Environmental Fatigue Analyses for RPV and Class 1 Piping (Section 4.3.5)
- Reactor Vessel Internals Fatigue Analyses (Section 4.3.6)
- High-Energy Line Break (HELB) Analyses Based on Cumulative Fatigue Usage (Section 4.3.7)
- Inservice 60-Year Flaw Growth Analyses (Section 4.3.8)

4.3.1 TRANSIENT CYCLE AND CUMULATIVE USAGE PROJECTIONS FOR 80 YEARS

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients usually described in design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. The existing fatigue analyses are based upon the number of transient cycles postulated to bound 60 years of service.

Projections of the transient cycles through the second period of extended operation 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 for PBAPS Units 2 and 3 respectively.

A review of Fatigue Monitoring (B.3.1.1) program data was performed to trend the number of cumulative transient cycles for each transient type that occurred at PBAPS Units 2 and 3 up to December 31, 2015. Since most nuclear power plants, including PBAPS Units 2 and 3, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provides an accurate basis for future projections. Therefore, each transient was evaluated to determine if the recent 15-year trend had a consistent cycle accumulation rate; and if so, the 15-year rate was used for most transients to extrapolate the projected number of future occurrences beginning January 1, 2016 and ending at the end of the unit's 80-year life. In a few cases, a longer-term rate was applied to determine the projected number of future occurrences. For both cases, the 80-year projected number of occurrences was determined by adding the number of past occurrences up to December 31, 2015 to the number of predicted future occurrences.

For transient numbers 27a, "HPCI Injection"; 27b "RCIC Injection"; 29, "SRV LIFT"; and 30, "Loss of RWCU and Restart of RWCU," the number of projected cycles for 80 years is based on a conservatively large number of assumed cycles which result in successfully meeting the appropriate CUF or CUF_{en} acceptance criterion for the affected bounding locations. The conservatively large number of assumed cycles bound the cumulative to-date cycles (12/31/15) by at least a factor of two. For transient number 29, "SRV LIFT" and transient number 30, "Loss of RWCU and Restart of RWCU" the assumed number of transient cycles equals the number of cycles which were assumed in the associated fatigue evaluation.

The 80-year projections of the Unit 2 "Startup and Heatup" transient cycle (number 3 on Table 4.3.1-1) and the Unit 2 "Shutdown – Cooldown (from 561ºF to 70ºF)" transient cycle (number 21 on Table 4.3.1-1) are based on 10-year trends that reflect the time period between January 1, 2005 and December 31, 2015. This refinement is valid since the Unit 2 trends for these transient cycles show a reduced rate of accumulation starting in approximately 2005.

For transient numbers 13, "Scram – Reactor Overpressure with Delayed Scram, Feedwater On, and Isolation Valves Open"; 31, "Operating-Basis Earthquake"; and 32, "Faulted Condition - Safe Shutdown Earthquake" which have never occurred, the projected number of transient cycles was assumed to be one over 80 years. For transient number 33, "Chugging"; 26 percent of the design number was assumed over 80 years.

Tables 4.3.1-1 and 4.3.1-2 provide the results of the 80-year transient cycle projections for PBAPS Units 2 and 3. The first column of each table provides the transients numbers. Note 1 provides the historical basis for the transients. The second column of each table provides the transient description and the third column of each table lists the cumulative numbers of transient cycles as of December 31, 2015. These counts include transient cycles during pre-operational startup.

The fourth column in Tables 4.3.1-1 and 4.3.1-2 shows the numbers of transient cycles projected to occur over 80 years. The fifth column in both Tables 4.3.1-1 and 4.3.1-2 lists the design transient cycles, which are the assumed numbers of transient cycles analyzed in the most recent fatigue analyses for components requiring CUF analyses in accordance with ASME Section III. Several of the 80-year transient cycle projections in the fourth column of each table exceed the assumed number of original design transient cycles in the fifth column. However, the assumed number of design transient cycles does not represent a final design limit; rather, the design limit is that the CUF or CUF_{en} does not exceed a value of 1.0. Since the CUF or CUF_{en} of a component is computed as a function of multiple thermal and pressure transients, increasing the number of transient cycles for one transient type to a value greater than the number assumed in the fatigue analysis may not cause the CUF or CUF_{en} to exceed the design limit. The 80-year projected transient cycle numbers shown in the fourth column of each table were used as input to calculate the projected 80-year CUF and CUF_{en} values shown in Table 4.3.1-3. All projected 80-year CUF and CUF_{en} values in Table 4.3.1-3 meet the appropriate acceptance criteria (e.g., CUF limit of 1.0 for ASME Section III locations, CUF screening limit of 0.1 for HELB locations, and CUF_{en} limit of 1.0).

Consistent with Section X.M1 of the GALL-SLR Report, the Fatigue Monitoring program monitors applicable plant transients that cause cyclic strains and contribute to fatigue, as specified in the underlying component fatigue analyses, and monitors or validates appropriate environmental parameters that contribute to environmental fatigue multiplier (F_{en}) values. The number of occurrences and the severity of the plant transients that contribute to the fatigue analyses for each component are monitored. SI:FatiguePro^{TM} is used at PBAPS to determine the overall effect of the cumulative numbers of transient cycles that have occurred at a given time and determines the CUF values for all monitored locations resulting from the combination of transient cycles that have occurred during the period.

The first PBAPS License Renewal Application committed to enhancing the Fatigue Monitoring program to include automated transient cycle counting and automated calculation and tracking of fatigue CUFs. As a result, the PBAPS SI:FatiguePro^{TM} software was updated in 2010. SI:FatiguePro^{TM} is a computerized data acquisition, recording, and thermal transient and cumulative fatigue usage tracking program.

The PBAPS SI:FatiguePro^{TM} automated transient cycle counting module uses temperature and pressure parameters, including the rates of changes of these parameters, to properly count and categorize transient cycles and calculate CUFs for critical plant components. The transient cycles assigned by SI:FatiguePro^{TM} are periodically reviewed to ensure all transient cycles are correctly captured and assigned. This review also ensures that the cyclic load severities used in the fatigue parameter calculations remain bounding.

In 2015, the PBAPS SI:FatiguePro^{TM} software was modified to include the calculation and tracking of Environmentally Assisted Fatigue (EAF) in accordance with NUREG/CR-6909 Revision 0 (Reference 4.8.39) at the locations identified in NUREG/CR-6260 (Reference 4.8.38) for the older-vintage General Electric plant, as well as other limiting plant-specific locations. For these locations, CUF_{en} is calculated and tracked by the program. Actual plant water chemistry conditions are periodically reviewed and compared to the conditions assumed in the EAF calculations to confirm that the water chemistry parameters used to calculate the F_{en} values remain valid.

The CUF and CUF_{en} values for the components monitored by SI:FatiguePro™ are compared to appropriate acceptance criterion (e.g., 1.0 for ASME Section III locations, 0.1 for HELB locations, or 1.0 for CUF_{en}). As long as the CUF values do not exceed the allowable values, the design limits remain satisfied. If monitored incremental CUF or CUF_{en} values exceed 80 percent of the applicable limit, then the condition will be entered into the corrective action program and evaluated for corrective action to be taken prior to exceeding the applicable final design limit acceptance criterion.

Eighty-year projections of CUF and CUF_{en} for the limiting locations monitored at PBAPS Units 2 and 3 are shown on Table 4.3.1-3. Monitoring of the limiting locations using SI:FatiguePro™ maintains assurance that all Class 1 locations remain bounded and design limits for fatigue and EAF remain satisfied throughout second period of extended operation and allow for sufficient time to initiate actions when design limits are approached.

Since the methodology that calculated the 80-year CUF and CUF_{en} projections assumed the larger number transient cycle projections from either Unit 2 in Table 4.3.1-1 or Unit 3 in Table 4.3.1-2, the projected 80-year CUF and CUF_{en} values in Table 4.3-1-3 are bounding to both Units 2 and 3.

The last column in Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3 document applicable PBAPS UFSAR sections.

The 80-year transient cycle projections provided in Table 4.3.1-1 and Table 4.3.1-2, and the resulting 80-year CUF and CUF_{en} projections provided in Table 4.3.1-3, were used to evaluate the fatigue TLAAs in Sections 4.3.2 through 4.3.8, and Sections 4.6 and 4.7. The SI:FatiguePro™ software will monitor the transients provided in Table 4.3.1-1 and Table 4.3.1-2 in the second period of extended operation.

Table 4.3.1-1
PBAPS Unit 2 – 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/15)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	UFSAR Sections and Tables
1	Boltup	56	74 (Note 7)	66	Table 4.2.4
2	Design Hydrostatic Test to 1,250 psig	39	55	130	Table 4.2.4
3	Startup and Heatup (100ºF/hr. max)	143	186 (Note 7)	161	Table 4.2.4, and Sections C.5.3.6 and C.5.3.2.2
3a	Excessive Rate Startup and Heatup (>100ºF/hr. <160ºF/hr.)	2	4	10	(Note 2)
4	Turbine Roll and Increase to 100% Power	145	196 (Note 7)	161	Table 4.2.4, and Section C.5.3.6
9	Loss of FW Heaters – Turbine Trip at 25% Power	9	17 (Note 7)	10	Table 4.2.4, and Section C.5.3.6
10	Loss of FW Heaters – FW Heater Bypass	29	40	70	Table 4.2.4, and Section C.5.3.6
11	Scram – Loss of Feedpumps – Isolation Valves Close	6	12 (Note 7)	10	Table 4.2.4, and Section C.5.3.6
13	Scram – Reactor Overpressure with Delayed Scram, Feedwater On, and Isolation Valves Open	0	1	1	Table 4.2.4, and Section C.5.3.6
14	Scram – Single Relief or Safety Valve Blowdown	10	19	40	Table 4.2.4 and Sections C.5.3.6 and C.5.3.2.2
15	Scram – Scram – T/G Trip – FW On – Isolation Valves Open, All Other Scrams	165	199 (Note 7)	187	Table 4.2.4, and Section C.5.3.6

Table 4.3.1-1
PBAPS Unit 2 – 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/15)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	UFSAR Sections and Tables
17	Improper Start of Cold Recirculation Loop	6	12	40	Table 4.2.4, and Section C.5.3.6
18	Sudden Start of Pump in Cold Recirculation Loop	5	10	40	(Note 3)
19	Reduction to 0% Power	142	185 (Note 7)	161	Table 4.2.4
20	Hot Standby FW Cycling	1	4	2600	(Note 5)
21	Shutdown – Cooldown from 561ºF to 70 ºF (100ºF/hr. max)	142	185 (Note 7)	161	Table 4.2.4, and Sections C.5.3.6 and C.5.3.2.2
21a	Shutdown – Excessive Cooldown Rate (>100ºF/hr.<160ºF/hr.)	1	2	10	(Note 2)
22	Shutdown – Vessel Flooding	137	168 (Note 7)	161	Table 4.2.4
24	Hydrostatic Test at 1563 psig	2	2	3	Section C.5.3.2.2
25	Unbolt	56	74 (Note 7)	66	Table 4.2.4
27a	HPCI Injection	14	38 (Note 6)	10	Table 4.2.4 and Section C.5.3.2.2
27b	RCIC Injection	12	165 (Note 6)	10	Table 4.2.4, and Section C.5.3.6
29	SRV LIFT	57	800 (Note 8)	800	Table 4.2.4, and Section C.5.3.6
30	Loss of RWCU and Restart of RWCU	105	240 (Note 8)	240	(Note 4)
31	Operating-Basis Earthquake	0	1	5	Section C.5.3.2.2

Table 4.3.1-1 PBAPS Unit 2 – 80-Year Transient Cycle Projections					
Transient Number (Note 1)	**Transient Description**	**Cumulative Transient Cycles to-date (12/31/15)**	**80-Year Projected Transient Cycles**	**No. of Design Transient Cycles**	**UFSAR Sections and Tables**
32	Faulted Condition - Safe Shutdown Earthquake	0	1	1	Section C.5.3.2.2
33	FW Temp Reduction	429	680	2000	Table 4.2.4
34	Chugging	0	3037	11,390	Section M.3.7

NOTES:

Note 1: Transient cycle numbers 1 through 28 are based on the original GE reactor thermal cycle diagrams. Transient cycles 29 through 33 were added since they are associated with other transient cycles that contribute to fatigue usage. Transient cycles 5, 6, 7, 8, 16, 26, and 28 do not contribute to fatigue or are incorporated in other transients, and are therefore not listed in this table. Transient cycle 12 was combined with transient cycle 15 and transient cycle 23 was combined with transient cycle 21. Therefore, they are not listed in this table.

Note 2: These transient cycles are not currently specifically documented in PBAPS UFSAR Revision 26 and are addressed in UFSAR Table 4.2.4 by the general description of "Heat-up / Cooldown". Transient 3a and transient 21a were added to the Fatigue Monitoring program in 1996 based on industry operating experience. Corrective action has been initiated to add these transient cycle descriptions to the PBAPS UFSAR.

Note 3: This transient cycle is not documented in PBAPS UFSAR Revision 26. This transient was added to the program in 2001 as the result of a reassessment of the original fatigue analysis. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 4: This transient cycle is not documented in PBAPS UFSAR Revision 26. Automated monitoring for this transient was added to the program in 2012. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 5: This transient cycle is not documented in PBAPS UFSAR Revision 26. This transient is an input to feedwater nozzles cumulative usage. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 6: Although the number of Cumulative Transient Cycles To-Date (12/31/15) in column 3 and the number of 80-Year Projected Transient Cycles in column 4, for transients 27a and 27b exceeds the "original" number of design transients in column 5 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.

Note 7: These 80-year transient cycle projections exceed the assumed number of design transient cycles. However, the assumed number of design transient cycles do not represent a final design limit; rather, the design limits are: a CUF value 1.0 for ASME Section III components, a CUF value 0.1 for HELB exclusion components, or a CUF_{en} value of 1.0 for components which are evaluated for environmental assisted fatigue. If monitored incremental CUF or CUF_{en} values determined periodically by SI:FatiguePro^{TM} based on actual cycles exceed 80 percent of the applicable design limit during the second period of extended operation, then the condition will be entered into the Corrective Action Program and evaluated for corrective action to be taken prior to exceeding the applicable final design limit acceptance criterion.

Note 8: This transient projection conservatively assumes a large number of cycles which result in successfully meeting the appropriate CUF or CUF_{en} acceptance criterion for the affected bounding locations. The assumed number of transient cycles equals the number of cycles which were assumed in the associated fatigue evaluation and are more than twice the number of actual cycles experienced up to 12/31/15.

Table 4.3.1-2
PBAPS Unit 3 – 80-Year Transient Cycle Projections

Transient Number (Note 1)	**Transient Description**	**Cumulative Transient Cycles to-date (12/31/15)**	**80-Year Projected Transient Cycles**	**No. of Design Transient Cycles**	**UFSAR Sections and Tables**
1	Boltup	56	77 (Note 7)	66	Table 4.2.4
2	Design Hydrostatic Test to 1,250 psig	31	52	130	Table 4.2.4
3	Startup and Heatup (100ºF/hr. max)	111	140	161	Table 4.2.4, and Sections C.5.3.6 and C.5.3.2.2
3a	Excessive Rate Startup and Heatup (>100ºF/hr. <160ºF/hr.)	1	2	10	(Note 2)
4	Turbine Roll and Increase to 100% Power	119	161	161	Table 4.2.4, and Section C.5.3.6
9	Loss of FW Heaters – Turbine Trip at 25% Power	7	10	10	Table 4.2.4, and Section C.5.3.6
10	Loss of FW Heaters – FW Heater Bypass	38	64	70	Table 4.2.4, and Section C.5.3.6
11	Scram – Loss of Feedpumps – Isolation Valves Close	5	8	10	Table 4.2.4, and Section C.5.3.6
13	Scram – Reactor Overpressure with Delayed Scram, Feedwater On, and Isolation Valves Open	0	1	1	Table 4.2.4, and Section C.5.3.6
14	Scram – Single Relief or Safety Valve Blowdown	4	8	40	Table 4.2.4, and Sections C.5.3.6 and C.5.3.2.2
15	Scram – Scram – T/G Trip – FW On – Isolation Valves Open, All Other Scrams	143	174	187	Table 4.2.4, and Section C.5.3.6

Table 4.3.1-2
PBAPS Unit 3 – 80-Year Transient Cycle Projections

Transient Number (Note 1)	**Transient Description**	**Cumulative Transient Cycles to-date (12/31/15)**	**80-Year Projected Transient Cycles**	**No. of Design Transient Cycles**	**UFSAR Sections and Tables**
17	Improper Start of Cold Recirculation Loop	6	12	40	Table 4.2.4, and Section C.5.3.6
18	Sudden Start of Pump in Cold Recirculation Loop	8	16	40	(Note 3)
19	Reduction to 0% Power	111	140	161	Table 4.2.4
20	Hot Standby FW Cycling	2	8	2600	(Note 5)
21	Shutdown – Cooldown from 561ºF to 70 ºF (100ºF/hr. max)	111	140	161	Table 4.2.4, and Sections C.5.3.6 and C.5.3.2.2
21a	Shutdown – Excessive Cooldown Rate (>100ºF/hr.<160ºF/hr.)	2	4	10	(Note 2)
22	Shutdown – Vessel Flooding	112	143	161	Table 4.2.4
24	Hydrostatic Test at 1563 psig	2	2	3	Section C.5.3.2.2
25	Unbolt	56	77 (Note 7)	66	Table 4.2.4
27a	HPCI Injection	14	38 (Note 6)	10	Table 4.2.4 and Section C.5.3.2.2
27b	RCIC Injection	46	165 (Note 6)	10	Table 4.2.4, and Section C.5.3.6
29	SRV LIFT	36	800 (Note 8)	800	Table 4.2.4, and Section C.5.3.6
30	Loss of RWCU and Restart of RWCU	105	240 (Note 8)	240	(Note 4)
31	Operating-Basis Earthquake	0	1	5	Section C.5.3.2.2

Table 4.3.1-2
PBAPS Unit 3 – 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/15)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	UFSAR Sections and Tables
32	Faulted Condition - Safe Shutdown Earthquake	0	1	1	Section C.5.3.2.2
33	FW Temp Reduction	327	587	2000	Table 4.2.4
34	Chugging	0	3037	11,390	Section M.3.7

NOTES:

Note 1: Transient cycle numbers 1 through 28 are based on the original GEH reactor thermal cycle diagrams. Transient cycles 29 through 33 were added since they are associated with other transient cycles that contribute to fatigue usage. Transient cycles 5, 6, 7, 8, 16, 26, and 28 do not contribute to fatigue or are incorporated in other transients and are therefore not listed in this table. Transient cycle 12 was combined with transient cycle 15 and transient cycle 23 was combined with transient cycle 21. Therefore, they are not listed in this table.

Note 2: These transient cycles are not currently specifically documented in PBAPS UFSAR Revision 26 and are addressed in UFSAR Table 4.2.4 by the general description of "Heat-up / Cooldown". Transient 3a and transient 21a were added to the Fatigue Monitoring program in 1996 based on industry operating experience. Corrective action has been initiated to add these transient cycle descriptions to the PBAPS UFSAR.

Note 3: This transient cycle is not documented in PBAPS UFSAR Revision 26. This transient was added to the program in 2001 as the result a reassessment of the original fatigue analysis. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 4: This transient cycle is not documented in PBAPS UFSAR Revision 26. Automated monitoring for this transient was added to the program in 2012. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 5: This transient cycle is not documented in PBAPS UFSAR Revision 26. This transient is an input to feedwater nozzles cumulative usage. Corrective action has been initiated to add this transient cycle description to the PBAPS UFSAR.

Note 6: Although the number of Cumulative Transient Cycles To-Date (12/31/15) in column 3 and the number of 80-Year Projected Transient Cycles in column 4, for transients 27a and 27b exceeds the "original" number of design transients in column 5 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.

Note 7: These 80-year transient cycle projections exceed the assumed number of design transient cycles. However, the assumed number of design transient cycles do not represent a final design limit; rather, the design limits are: a CUF value 1.0 for ASME Section III components, a CUF value 0.1 for HELB exclusion components, or a CUF_{en} value of 1.0 for components which are evaluated for environmental assisted fatigue. If monitored incremental CUF or CUF_{en} values determined periodically by SI:FatiguePro™ based on actual cycles exceed 80 percent of the applicable design limit during the second period of extended operation, then the condition will be entered into the Corrective Action Program and evaluated for corrective action to be taken prior to exceeding the applicable final design limit acceptance criterion.

Note 8: This transient projection conservatively assumes a large number of cycles which result in successfully meeting the appropriate CUF or CUF_{en} acceptance criterion for the affected bounding locations. The assumed number of transient cycles equals the number of cycles which were assumed in the associated fatigue evaluation and are more than twice the number of actual cycles experienced up to 12/31/15.

Table 4.3.1-3
PBAPS Units 2 and 3 – Limiting Locations and 80-Year Projected CUF and CUF_{en} Values

No.	Location Description	80-Year CUF_{en}	80-Year CUF	Acceptance Criterion	UFSAR Sections and Tables
1	CRD Nozzles (LAS)/Vessel Partial Penetration Weld, Juncture 6	0.186	(Note 4)	1.0	New Location
2	Core Spray Nozzles (SS)/Thermal Sleeve Juncture 9 (Note 1)	0.510	(Note 4)	1.0	Table 4.2.4
3	Feedwater Nozzles (LAS)/Beyond Second Piston Ring (Note 1)	0.859	(Note 4)	1.0	Table 4.2.4
4	Feedwater Nozzles (CS)/Safe End Between First and Second Piston Ring (Note 1)	0.423	(Note 4)	1.0	Table 4.2.4
5	Recirculation Piping and RHR Return Line (CS)/RHR Return Pipe to Tee Weld Point 185 (Note 1)	0.103	(Note 4)	1.0	Table 4.2.4
6	Recirculation Piping and RHR Return Line (SS)/ Return Tee Point 84	(Note 2)	0.081	0.1 (Note 2)	Table 4.2.4
7	Recirculation Piping and RHR Return Line (SS)/Return Tee Point 84	0.373	(Note 4)	1.0	Table 4.2.4
8	Recirculation Piping and RHR Return Line (SS)/RHR Return Piping Point 134 (Note 1)	0.855	(Note 4)	1.0	Table 4.2.4
9	Recirculation Pump (LAS)/Cooler Studs	(Note 3)	0.600	1.0	New Location
10	Recirculation Pump (SS)/Cooler Cylinder	0.653	(Note 4)	1.0	New Location
11	Recirculation Pump (SS)/Heater Taper	0.382	(Note 4)	1.0	New Location
12	RHR Return Line (SS)/ Drywell Penetrations N-13A and B	0.133	(Note 4)	1.0	New Location
13	RHR Supply Line (CS)/Pipe to Penetration Weld Point 6	0.099	(Note 4)	1.0	New Location
14	RHR Supply Line (SS)/Pipe to Penetration Weld) Point 6	0.063	(Note 4)	1.0	New Location
15	RHR Supply Line(SS)/Drywell Penetrations N-12	0.439	(Note 4)	1.0	New Location
16	RHR Supply Line (SS) / Supply Tee Point 42	0.400	(Note 4)	1.0	Table 4.2.4
17	Recirculation Inlet Nozzle (SS)/Thermal Sleeve Section 7 (Note 1)	0.804	(Note 4)	1.0	Table 4.2.4
18	Recirculation Outlet Nozzle (SS)/Thermal Sleeve Section 3 (Note 1) (Note 7)	0.254	(Note 4)	1.0	Table 4.2.4

Table 4.3.1-3
PBAPS Units 2 and 3 – Limiting Locations and 80-Year Projected CUF and CUF_{en} Values

No.	Location Description	80-Year CUF_{en}	80-Year CUF	Acceptance Criterion	UFSAR Sections and Tables
19	RPV Region A (HS)/Closure Bolts	(Note 3)	0.969	1.0	Table 4.2.4
20	RPV Region A (LAS)/Refueling Containment Skirt Juncture 1 Outside Vessel	(Note 3)	0.460	1.0	Table 4.2.4
21	RPV Region B (LAS)/Stabilizer Brackets Bracket to Shell Juncture	0.418	(Note 4)	1.0	New Location
22	RPV Region B1 (LAS)/Shroud Support, Baffle Plate to Vessel Juncture (Note 6)	0.726	(Note 4)	1.0	New Location
23	RPV Region B1 (NI-Cr-Fe)/Shroud Support, Baffle Plate to Vessel Juncture (Note 6)	0.233	(Note 4)	1.0	Table 4.2.4
24	RPV Region B1 (NI-Cr-Fe)/Jet Pump Shroud Support, Diffuser Weld to Baffle Plate (Note 5)	0.984	(Note 4)	1.0	Table 4.2.4
25	RPV Region C (LAS)/Support Skirt Juncture 3 Inside	(Note 3)	0.933	1.0	Table 4.2.4
26	Torus (CS)/Unit 3 Torus Penetration N234B	(Note 3)	0.591	1.0	Table 4.2.4
27	Torus (CS)/ Torus Shell	(Note 3)	0.862	1.0	Table 4.2.4
28	Main Steam Pipe (CS)/MS Nozzle	0.16	(Note 4)	1.0	Table 4.2.4
29	Feedwater Piping(CS)/FW Nozzle	0.21	(Note 4)	1.0	Table 4.2.4
30	Vessel Shell (LAS)/RPV Region C	0.57	(Note 4)	1.0	Table 4.2.4

NOTES:
Note 1: NUREG/CR-6260 location for the older-vintage GEH plant.
Note 2: High Energy Line Break Exclusion Analysis location (see Section 4.3.7).
Note 3: CUF_{en} is not applicable for this location because it is not exposed to the reactor coolant environment.
Note 4: The CUF value is not included in the table because it is bounded by the CUF_{en} value in column 3.
Note 5: As documented in UFSAR Section C.5.3.2.2, the fatigue evaluation of this location included a main steam line break and subsequent LPCI injection (Faulted Condition).
Note 6: As documented in UFSAR Section C.5.3.2.2, the fatigue evaluation of this location includes a 10-minute SRV blowdown resulting in a plant shutdown.
Note 7: As documented in UFSAR Section C.5.3.6, the fatigue evaluation of this location assumed 8 cycles of single SRV or Safety Valve Blowdown resulting in a plant shutdown.

4.3.2 ASME SECTION III, CLASS 1 FATIGUE ANALYSES

TLAA Description:

The PBAPS reactor pressure vessels (RPVs) were originally designed for 40 years of service in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Winter Addendum for Units 2 and 3) for Class 1 design requirements. 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 design life of the plant in the design specifications. These Class 1 fatigue analyses were required to demonstrate that the Cumulative Usage Factor (CUF) for each component will not exceed the design limit of 1.0 for all the postulated transients. The original, 40-year RPV fatigue analyses were evaluated for a 60-year service life and for environmentally assisted fatigue (EAF) as part of the PBAPS first License Renewal Application (LRA). The 60-year evaluations now serve as the current licensing basis (CLB), and have been identified as TLAAs for the second period of extended operation.

All PBAPS piping systems were originally designed and evaluated in accordance with USAS (ANSI) B31.1 design requirements, which did not include explicit fatigue analysis. In the 1980s PBAPS replaced Class 1 reactor recirculation and the residual heat removal (RHR) system piping on both units. This replaced piping was designed in accordance with ASME Section III, 1980 Edition, including winter addenda through 1981, as Class 1 piping. In addition, on Unit 3, the flued-head penetrations for the RHR system were also replaced and analyzed for fatigue in accordance with ASME Section III, Class 1 requirements. Therefore, this replaced piping and flued-head penetrations were explicitly evaluated for fatigue. The remaining Unit 3 penetrations and all Unit 2 penetrations are designed in accordance with ASME Section III, Class 2 requirements, which do not include explicit fatigue analyses. ASME Class 2, 3 and ANSI B31.1 components use implicit fatigue analyses, which also are TLAAs and are addressed in Section 4.3.4.

In the first PBAPS License Renewal Application all ASME Section III, Class 1 fatigue analyses were identified as TLAAs and they were evaluated for 60 years of operation and dispositioned in accordance with 10 CFR 54.21(c)(iii) for management of the aging effect using the current Fatigue Monitoring program (Reference 4.8.58). Both PBAPS units have subsequently undergone a 12.4 percent Extended Power Uprate (EPU) in which the limiting fatigue analyses were re-evaluated for increased power levels for 60 years of operation. In addition, both PBAPS units were also evaluated for Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operation and for 1.7 percent Measurement Uncertainty Recapture (MUR) uprate. The Class 1 CLB fatigue analyses for the affected components were revised to evaluate the impact caused by these changes.

These Class 1 fatigue analyses have been identified as TLAAs that require evaluation for the second period of extended operation.

TLAA Evaluation:

All PBAPS ASME Section III Class 1 fatigue analyses are based on the transient cycles listed in Tables 4.3.1-1 and 4.3.1-2. Table 4.3.1-3 documents the 80-year CUF and CUF_{en} projections for all plant-specific limiting locations based on the 80-year transient cycle projections in table 4.3.1-1 and 4.3.1-2. Table 4.3.1-3 demonstrates that the 80-year projected values of CUF and CUF_{en}

for all locations remain less than the ASME Section III acceptance criterion through the second period of extended operation.

To ensure the projected CUF and CUF_{en} values in Table 4.3.1-3 remain acceptable for the 80-year period of operation for Units 2 and 3, the Fatigue Monitoring (B.3.1.1) program will monitor actual transient cycles and the associated CUF and CUF_{en} values for all limiting locations and ensure corrective actions are taken, if necessary, prior to exceeding the ASME Section III acceptance criterion.

The Fatigue Monitoring program will continue to use SI:FatiguePro™ to compute actual CUF and CUF_{en} values for all monitored locations. With this approach, the original numbers of design transient cycles are no longer a limit; instead the ASME Section III acceptance criteria are the limits for each monitored location (References 4.8.44 and 4.8.45).

The Fatigue Monitoring program includes requirements that initiate corrective actions if any CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected Class 1 fatigue analyses to address higher CUF or CUF_{en} values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flow tolerance analysis), or repair or replacement of affected components prior to the CUF or CUF_{en} values exceeding their allowed values.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – 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 (B.3.1.1) program through the second period of extended operation.

4.3.3 ASME SECTION III, CLASS 1 FATIGUE WAIVERS

TLAA Description:

The PBAPS reactor pressure vessels (RPVs) were originally designed for 40 years of service in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Winter Addendum) for Class 1 design requirements. The design stress reports for the Unit 2 and Unit 3 RPVs include fatigue waivers that determined that some RPV components did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 were satisfied. The PBAPS RPV components with fatigue waiver evaluations are listed in Table 4.3.3-1. Since the ASME Section III, Paragraph N-415.1 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 the second period of extended operation using the 80-year projected number of transients in Tables 4.3.1-1 and 4.3.1-2.

Table 4.3.3-1 RPV Components Exempt Per ASME Section III, N-415.1
Steam Outlet Nozzle
Liquid Control Nozzle
Instrumentation Nozzle
Vent Nozzle
Jet Pump Instrument Nozzle
RPV Drain Nozzle

TLAA Evaluation:

The original Class 1 fatigue waivers included assumptions for the total postulated number of temperature and pressure transients that were expected over the 40-year life of the plant. In addition, the original waivers evaluated significant load fluctuations expected over the 40-year life of the plant. Similar transients were combined into event groups and were assigned bounding temperature and pressure ranges. The event groups and applicable nozzles are shown in columns 1 and 2 of Table 4.3.3-2. Column 3 documents the specific transients, from Tables 4.3.1-1 and 4.3.1-2, which make up each event group and column 4 documents the number of grouped events assumed in the original waivers.

The fatigue waivers were reevaluated for the second period of extended operation in accordance with the applicable ASME Section III, Paragraph N-415-1 criteria. The number of grouped events were increased in the reevaluation to bound or equal the summation of 80-year projections for the applicable transients listed in Table 4.3.1-1 and 4.3.1-2. Pressure and temperature ranges for each event group were adjusted for EPU operating conditions. Table 4.3.3-2, column 5 shows the number of events assumed in the waiver reevaluation, column 6 shows the sum of the applicable 80-year projections from Table 4.3.1-1, and column 7 shows the sum of the applicable 80-year projections from Table 4.3.1-2.

In addition, the reevaluation evaluated the significant load fluctuations acting at each nozzle expected over the 80-year life of the plant.

The results of the reevaluation showed that the criteria in ASME Section III, Paragraph N-415-1 remain satisfied for the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The ASME Section III Class 1 fatigue waiver acceptance criterion continues to be satisfied based on 80-year projected transient cycles through the second period of extended operation.

Table 4.3.3-2
Transient Summary for Fatigue Wavier Reevaluation

Event Grouping Assumed in the Original Waiver	Applicable Nozzles	Applicable Transients, from Tables 4.3.1-1 and 4.3.1-2, for Each Event Grouping Assumed in the Original Waiver	Number of Events Assumed in the Original Waiver	Number of Events Assumed in the Waiver Reevaluation	Uni 2 - Number of 80-Year Projections for Event Grouping from Table 4.3.1-1	Unit 3 - Number of 80-Year Projections for Event Grouping from Table 4.3.1-2
Atmospheric to Operating Conditions and Back Transients	All Nozzles	2) Hydrostatic Test 3), 3a), and 19) Startup/Shutdown 11) SCRAM: Loss of FW pumps 24) Pre-op Hydrotest	263	266	259	204
Startup and Shutdown Transients.	All Nozzles	3), 3a) and 19) Startup/Shutdown	120	197	190	142
Significant Temperature Fluctuation Transients	• Steam Outlet • Instrumentation • Vent nozzle	11) SCRAM: Loss of FW Pumps 13) SCRAM: Rx Overpressure 14) SCRAM: SRV Blowdown	23	44	44	25
	• Liquid Control	Liquid Control Operation (1) 11) SCRAM: Loss FW pumps 14) SCRAM: SRV Blowdown) 18) Sudden Recirc Loop Start	27	42	42	33
	• Jet Pump Instrument	17) Improper Recirc Loop Start 11) SCRAM: Loss FW pumps 14) SCRAM: SRV blowdown	37	67	67	44
	• RPV Drain	11) SCRAM: Loss of FW pumps 14) SCRAM: SRV Blowdown 18) Sudden Recirc Loop Start	17	41	41	32

4.3.4 ASME SECTION III, CLASS 2, CLASS 3, AND ANSI B31.1 ALLOWABLE STRESS ANALYSES

TLAA Description:

The PBAPS System Group II and III (ASME Section III, Class 2 and Class 3) safety-related piping, and other piping that is in scope for license renewal, was originally designed in accordance with the 1967 Edition of the USAS (ANSI) B31.1 Power Piping Code (ANSI B31.1). Piping systems designed in accordance with the ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but rather cyclic loading is considered in a simplified manner in the design process. ANSI B31.1 requires a stress range reduction factor be used based on the number of thermal and pressure cycles expected during the component operating lifetime. If the total number of fatigue cycles is expected to be 7000 or less, the stress range reduction factor of 1.0 is applied. For higher numbers of fatigue cycles, a stress range reduction factor of less than 1.0 is applied to the piping, which reduces the alternating stress range, reducing the likelihood of failure due to cyclic loading. The stress range reduction factors for piping designed to ANSI B31.1 requirements are shown in Table 4.3.4-1. The evaluation for required stress range reduction factors performed as part of piping design per ANSI B31.1 are implicit fatigue analyses since they are based upon the number of fatigue cycles anticipated for the life of the component, therefore they are TLAAs requiring evaluation for the second period of extended operation.

Table 4.3.4-1
Stress Range Reduction Factors for Piping Designed per ANSI B31.1

Number of Equivalent Full Temperature Cycles	Stress Range Reduction Factor
7,000 and less	1.0
7,000 to 14,000	0.9
14,000 to 22,000	0.8
22,000 to 45,000	0.7
45,000 to 100,000	0.6
100,000 and over	0.5

TLAA Evaluation:

SLRA Tables 3.x.2-y (see SLRA Section 3.0) identify piping, piping components, bolting, and valve bodies located within license renewal piping systems that were designed in accordance with ANSI B31.1. This includes components which are currently designated as ASME Section XI Class 1 components but were designed in accordance with ANSI B31.1. The identified piping components, bolting, and valve bodies are not associated with explicit cumulative fatigue usage analyses but rather support the piping system's implicit ANSI B31.1 fatigue analyses.

Portions of the following license renewal piping systems were designed in accordance with ANSI B31.1 requirements, but are attached to ASME Section III, Class 1 piping and are only affected by the same pressure and temperature transients as the Reactor Coolant System transients that are listed in Table 4.3.1-1 and Table 4.3.1-2: Control Rod Drive, Core Spray, Feedwater, Main Steam, Offgas and Recombiner, Primary Containment Isolation, Reactor Recirculation, Reactor Vessel Instrumentation, Residual Heat Removal, and Standby Liquid Control. Only a subset of the transients listed in Table 4.3.1-1 and Table 4.3.1-2 apply to the Class 2, Class 3, and ANSI B31.1 piping within each system. The summation of all 80-year transient cycle projections from each table is less than 3,500 cycles. Therefore, even if all operational Reactor Coolant System transients (transients 1 through 33) applied to each of these systems, the total number of projected 80-year cycles is less than 50 percent of 7000. Therefore, the stress range reduction factors originally applied for the components within these piping systems remain applicable and these implicit TLAAs remain valid through the second period of extended operation.

Portions of the following systems were designed in accordance with ANSI B31.1 requirements and are affected by thermal and pressure transients that are different than the Reactor Coolant System transients that are listed in Table 4.3.1-1 and Table 4.3.1-2: Auxiliary Steam, High Pressure Coolant Injection (steam supply and turbine exhaust piping), Reactor Water Cleanup, Reactor Core Isolation Cooling (steam supply and turbine exhaust piping), Emergency Diesel Generator (engine exhaust piping), and Fire Protection (engine exhaust piping). Table 4.3.4-2 provides descriptions of the transient cycles that result in thermal or pressure cycles for these piping systems and the 80-year projected number of cycles through the second period of extended operation. In all cases the 80-year projected number of fatigue cycles is substantially less than 7000. Therefore, the stress range reduction factors originally applied for the components within these piping systems remain applicable and these implicit TLAAs remain valid through the second period of extended operation.

In addition, various high temperature sample lines in the Process Sampling System were designed in accordance with ANSI B31.1 requirements. Table 4.3.4-3 provides descriptions of the transient cycles that result in thermal or pressure cycles for these sample lines and the 80-year projected number of cycles through the second period of extended operation. In all cases the 80-year projected number of fatigue cycles is substantially less than 7000. Therefore, the stress range reduction factors originally applied for these sample lines remain applicable and the implicit TLAAs associated with these sample lines remain valid through the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – All ASME Section III, Class 2, Class 3, and ANSI B31.1 allowable stress analyses remain valid through the second period of extended operation.

Table 4.3.4-2

80-Year Transient Cycle Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems Affected by Transients Other Than RCS Transients

Piping System	Description of Transient Cycles that Affects the Piping System	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
Auxiliary Steam System (Heating Steam and HPCI/RCIC Steam Supply Piping)	Preoperational Testing	40 Startups	1050
	Heating Season	10 Startups per Year / 85 years	
	RCIC Turbine Testing	120 Startups	
	HPCI Turbine Testing	40 Startups	
HPCI System (Steam Supply Piping)	RCS Transients that affect Class 1 Main Steam System from Tables 4.3.1-1 and 4.3.1-2 apply	Assume 3500 Cycles (Bounds Total Number of Operational Transients Numbers From Tables 4.3.1-1 or 4.3.1-2)	3660
	Restoration of Steam Supply to HPCI Turbine after system maintenance	2 Cycles per Year	
RCIC System (Steam Supply Piping)	RCS Transients that affect Class 1 Main Steam System from Tables 4.3.1-1 and 4.3.1-2 apply	Assume 3500 Cycles (Bounds Total Number of Operational Transients Numbers From Tables 4.3.1-1 or 4.3.1-2)	3660
	Restoration of Steam Supply to RCIC Turbine after system maintenance	2 Cycles per Year	
HPCI System (Turbine Exhaust Piping)	Preoperational Testing	25 Startups	875
	HPCI Injections (Other Than Loss of FP) (Ref. Tables 4.3.1-1, 4.3.1-2)	38 Startups	
	Scram Loss of FP – Isolation Valves Close (Ref. Tables 4.3.1-1, 4.3.1-2)	Unit 2 – 12 Startups Unit 3 - 8 Startups	
	HPCI Starts After Maintenance	2 Startups per Year	
	HPCI Starts - Surveillances	8 Startups per Year	

Table 4.3.4-2

80-Year Transient Cycle Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems Affected by Transients Other Than RCS Transients

Piping System	Description of Transient Cycles that Affects the Piping System	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
RCIC System (Turbine Exhaust Piping)	Preoperational Testing	25 Startups	1082
	RCIC Injections (Other Than Loss of FP) (Ref. Tables 4.3.1-1, 4.3.1-2)	165 Startups	
	Scram Loss of FP – Isolation Valves Close (Ref. Tables 4.3.1-1, 4.3.1-2)	Unit 2 – 12 Startups Unit 3 – 8 Startups	
	RCIC Starts After Maintenance	2 Startups per Year	
	RCIC Starts - Surveillances	9 Startups per year	
Emergency Diesel Generator System (Each Engine) (EDG Exhaust Piping)	Preoperational Testing	100 Startups	2872
	Diesel Starts - Intended Function	1 Startups Per Year	
	Diesel Starts – Surveillances	Currently 18 Startups per Year (An additional 1012 cycles were added due to frequent testing early the site's life)	
	Diesel Starts After Maintenance	3 Startups per Year	
Fire Protection System (Fire Pump Diesel Engine Exhaust Piping)	Preoperational Testing	100 Startups	1630 (Assumed 85 Years)
	DDFP Starts - Intended Function	1 Startup per Year	
	DDFP - Surveillances	15 Startups per Year	
	DDFP – Post Maintenance Testing	1 Startup per Year	
	DDFP Starts Not associated with Maintenance or Testing	1 Startup per Year	

Table 4.3.4-2

80-Year Transient Cycle Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems Affected by Transients Other Than RCS Transients

Piping System	Description of Transient Cycles that Affects the Piping System	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
Reactor Water Cleanup	RCS Transients that affect RWCU System from Tables 4.3.1-1 and 4.3.1-2 apply	Assume 3500 Startups (Bounds Total Number of Operational Transients Numbers From Tables 4.3.1-1 or 4.3.1-2)	3990
	RWCU Preoperational Testing	10 Startups	
	RWCU Pump Swap	2 Startups per Year	
	RWCU Pump Maintenance	1 Startup per Year	
	RWCU Heat Exchanger Swap	2 Startups per Year	
	RWCU Heat Exchanger Maintenance	1 Startup per Year	

Table 4.3.4-3

80-Year Transient Cycle Projections for High Temperature Process Sample System Lines

Sample Line	Description of Transient Cycles that Affects the Sample Line	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
Units 2 and 3 A, B, C, and D RHR Heat Exchanger Outlet Sample Lines	Manual sampling during plant shutdown to cold shutdown.	Twenty-five per plant shutdown. 185 plant shutdowns are projected for 80 years from Table 4.3.1-1. (Subtotal – 4625)	4785
	Transients resulting from system maintenance.	Two per year. (Subtotal – 160)	
Units 2 and 3 Main Steam Sample Line	Manual sampling during plant operation.	Once per month. (Subtotal – 960)	1120
	Transients resulting from system maintenance.	Two per year. (Subtotal – 160)	
Units 2 and 3 Recirculation System sample line to ECP/Crack Growth Monitor	Sample line is in service continuously during reactor power operations.	Four per year. (Subtotal – 320)	480
	Transients resulting from system maintenance.	Two per year. (Subtotal – 160)	
Units 2 and 3 RWCU Regen HX Outlet sample line	Manual sampling during plant operation.	Once per month. (Subtotal – 960)	1120
	Transients resulting from system maintenance.	Two per year. (Subtotal – 160)	
Units 2 and 3 Reactor Feedwater Sample Line	Sample line is in service continuously during reactor power operations.	Four per year. (Subtotal – 320)	480
	Transients resulting from system maintenance.	Two per year. (Subtotal – 160)	

4.3.5 ENVIRONMENTAL FATIGUE ANALYSES FOR RPV AND CLASS 1 PIPING

TLAA Description:

NUREG-2191 Section X.M1, Fatigue Monitoring, provides guidance for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact the reactor coolant. One acceptable method for satisfying this guidance is to assess the impact of the reactor coolant environment on a sample set of critical components. These critical components should include those listed in NUREG/CR-6260 (Reference 4.8.38) for the plant type and vintage, although plant-specific justification can be provided to demonstrate that calculations for the NUREG/CR–6260 locations do not need to be included. Additional component locations should also be considered if they are more limiting than those listed in NUREG/CR-6260 for the plant.

In 2015, the PBAPS SI:FatiguePro™ software was modified to include the calculation and tracking of Environmentally Assisted Fatigue (EAF) cumulative usage factors (CUF_{en}) at the locations identified in NUREG/CR-6260 (Reference 4.8.38) for the older-vintage GEH plant, as well as other locations in contact with reactor water that were monitored by SI:FatiguePro™. For these locations, the CUF_{en} values are calculated in accordance with NUREG/CR-6909, Revision 0 (Reference 4.8.39) and tracked by the Fatigue Monitoring (B.3.1.1) program since 2015.

TLAA Evaluation:

For the SLR application environmental fatigue calculations were prepared in accordance NUREG/CR-6909, Revision 1 (Reference 4.8.40) for component location listed in NUREG/CR-6260 for the older-vintage BWR, which correlates to PBAPS. Also, for the SLR application, environmental fatigue screening calculations were performed for all RPV, piping, and other component locations that have an identified CUF value in a PBAPS CLB stress report or evaluation and are in contact with reactor water.

Consistent with NUREG-2191, Section X.M1, environmental effects were evaluated using the guidance in Regulatory Guide (RG) 1.207, Revision 1, which specifies the following:

Carbon and Low Alloy Steels

- The formula provided in Appendix A of NUREG/CR-6909, Revision 1 (Reference 4.8.40), using the fatigue design curve for carbon and low alloy steel provided in NUREG/CR-6909, Revision 1 (Figure A.1 and A.2, respectively, and Table A.1).

Austenitic Stainless Steels

- The formula provided in NUREG/CR-6909, Revision 1, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909, Revision 1 (Figure A.3 and Table A.2).

Nickel Alloys

- The formula provided in NUREG/CR-6909, Revision 1, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909, Revision 1 (Figure A.3 and Table A.2).

Environmental Fatigue Screening

The environmental fatigue screening calculation methodology is described below.

1) All component locations that have a documented cumulative usage factors in the PBAPS CLB were identified.

2) Each identified location was categorized as to whether the location is in contact with reactor water.

3) Component locations in contact with reactor water in which CUF_{en} values are already calculated and monitored by SI:FatiguePro™ were identified. All these component locations were selected for more detailed fatigue and EAF analysis in accordance with NUREG 6909, Revision 1.

4) Component locations in contact with reactor water that are not monitored by SI:FatiguePro™ were identified and the following was performed for these locations.

    a. For each of component location the technical rigor in which the original CUF value was determined. For example, the location was evaluated to ASME Section III, Subsection NB-3600.

    b. For each component location it was determined if the original CUF value is the result of “lumped” transient assumptions.

    c. For each component location a 80-year CUF value was estimated, for screening purposes only, based on linear extrapolation of the corresponding published 40-year or 60-year CUF values.

5) Locations that undergo essentially the same thermal and pressure transients during plant operations were grouped together into the same thermal zones.

6) Within each material type in a thermal zone, for locations in which EAF is applicable, the screening 80-year CUF is greater than 0.25, and the location is not monitored by SI:FatiguePro™, the following was performed:

    a. The location with the greatest estimated screening 80-year CUF value was selected.

    b. The top two locations with the greatest two estimated screening 80-year CUF values were selected, if the estimated screening 80-year CUF values of these locations are within a factor of two.

    c. The top three locations within each material type were selected, if the estimated screening 80-year CUF values for the three locations are within 25 percent of each other.

d. It was verified that locations that were eliminated were originally evaluated to the same technical rigor as those locations which were selected.

7) For selected locations, calculate a screening F_{en} value based on the material, operating temperature, and chemistry was calculated; and a screening 80-year CUF_{en} value was calculated.

8) All the selected locations with screening 80-year CUF_{en} values greater than 0.25 were identified and more detailed fatigue and EAF analyses in accordance with NUREG 6909 were performed.

This methodology resulted in the detailed EAF analysis of a large majority of component locations that have an identified CUF value in a PBAPS CLB stress report or evaluation and are in contact with reactor water. For example, of the 32 component locations that have an identified CUF value in a PBAPS CLB stress report or evaluation and for which EAF applies, 23 component locations were evaluated for detailed EAF analysis. These 23 component locations will be monitored by SI:FatiguePro™ during the second period of extended operation. Also, locations that were eliminated were verified to have been originally evaluated to the same technical rigor as those locations which are selected.

In the PBAPS screening calculations, for each wetted material within a system, a new CUF value in air was computed using the applicable NUREG/CR-6909, Revision 1 fatigue curve and the alternating stress values from the existing ASME Code fatigue calculation. F_{en} multipliers were computed based upon the applicable formula provided in NUREG/CR-6909, Revision 1 for each material using dissolved oxygen values that yielded the largest F_{en} values. Dissolved oxygen values were determined for different regions within the RPV and Class 1 piping systems using the EPRI BWRVIA radiolysis computer model. The model is designed to predict dissolved oxygen and dissolved hydrogen concentrations at various locations within the RPV and piping based upon chemical sampling and monitoring data. The reactor coolant dissolved oxygen values were significantly reduced by hydrogen water chemistry and noble metal injection strategies employed for each PBAPS unit, which were accounted for in the determination of the F_{en} multipliers. Each PBAPS unit was initially operated using Normal Water Chemistry (NWC), followed by Hydrogen Water Chemistry (HWC), then by the current strategy of simultaneously employing HWC plus Noble Metal Chemical Addition (NMCA). Dissolved oxygen values were determined for each of these operating regimes (NWC and HWC/HWC + NMCA) for each region of the RPV and for each affected Class 1 piping system. Values that yield the highest F_{en} multipliers were chosen for each operating regime.

Environmental Fatigue Analyses

The 80-year projected cycles shown in Tables 4.3.1-1 and 4.3.1-2 were used as inputs in the environmental fatigue analyses. As discussed in Section 4.3.1, the 80-year projected CUF_{en} values in Table 4.3.1-3 conservatively use the larger number transient cycle projections from either Unit 2 or 3, so the results in Table 4.3.1-3 are applicable to both units.

The environmental fatigue analyses described within this section will be incorporated into the CLB prior to the start of the second period of extended operation. The environmental fatigue analyses will be managed by the Fatigue Monitoring (B.3.1.1) program using the SI:FatiguePro™ software, including periodic validation of cycles and water chemistry parameters that contribute to F_{en}, as discussed in Section 4.3.1. The Fatigue Monitoring program includes requirements that initiate corrective actions if any CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criterion. Corrective actions may include revision of the affected environmental fatigue analysis to qualify an increased number of cycles determined to bound 80 years of operation, repair, replacement, or establishing an inspection program using an approach acceptable to the NRC (such as an inspection program performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis) prior to the CUF_{en} value exceeding the allowed value.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The Fatigue Monitoring (B.3.1.1) program is credited with managing the effects of environmental fatigue on the intended functions of all RPV and Class 1 piping components through the second period of extended operation.

4.3.6 REACTOR VESSEL INTERNALS FATIGUE ANALYSES

The PBAPS reactor vessel internals were not designed in accordance with ASME Section III. However, some of the reactor vessel internals were evaluated for fatigue using methods from ASME Section III. Searches were performed to identify any potential TLAAs associated with fatigue of reactor vessel internal components within the current licensing basis for PBAPS Units 2 and 3. Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as PBAPS fatigue TLAAs are evaluated in the following subsections:

- Generic BWR Fatigue Analyses for Various Reactor Vessel Internal Components (Section 4.3.6.1).
- Generic BWR Fatigue Analyses for the Core Shroud (Section 4.3.6.2).
- Core Shroud Support Fatigue Analysis Reevaluation (Section 4.3.6.3).
- Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis (Section 4.3.6.4).
- Replacement Steam Dryer Stress Report and Fatigue Evaluation (Section 4.3.6.5)

4.3.6.1 GENERIC BWR FATIGUE ANALYSES FOR VARIOUS REACTOR VESSEL INTERNAL COMPONENTS

TLAA Description:

The PBAPS Extended Power Uprate (EPU) license amendment submittal to the NRC in 2012 (Reference 4.8.70) and the Measurement Uncertainty Recapture (MUR) Power Uprate license amendment submittal to the NRC in 2017 (Reference 4.8.57) documented generic BWR fleet 40-year and 60-year CUF values for various reactor vessel internal components. The generic 40-year and 60-year values, which are shown on Table 4.3.6.1-1, were calculated by GEH for the BWR fleet and are bounding for PBAPS. The generic CUF values were used in the submittals to demonstrate that PBAPS reactor vessel internal components are structurally qualified for operation in the EPU and MUR operating conditions for a 60-year plant life.

The generic 40-year design CUF values were calculated by GEH in BWR fleet fatigue analyses which assumed various normal, upset, emergency, or faulted transient severities and numbers of transient cycles. The generic 60-year CUF values were calculated by multiplying the generic 40-year design CUF values by 1.5.

Since the generic analyses, which resulted in calculated CUF values, were used to demonstrate that PBAPS reactor vessel internal components are structurally qualified for EPU and MUR conditions, and they have assumed transient cycle inputs reflective of 60 years of operation, they have been identified as TLAAs that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

Table 4.3.6.1-1 documents the generic reactor vessel internals 40-year and 60-year CUF values reported in the PBAPS license amendment submittals for EPU and MUR (Reference 4.8.70 and 4.8.57, respectively). 80-year CUF values for each component are shown in the last column of the table. Except for the “Shroud” component, the 80-year CUF values were calculated by multiplying the 40-year CUF values by two.

Multiplying the calculated 40-year CUF values by two to obtain 80-year CUF projected values is a reasonable approach since, in order for the actual CUF values to approach twice the original calculated CUF values, the unit would have to experience twice as many actual transient cycles than originally assumed. For example, all the projected 80-year transient cycles numbers in column 4 of Tables 4.3.1-1 and 4.3.1-2 are significantly less than twice the number of the assumed transients in column 5, except for transients no. 27a, “HPCI Injection”, and 27b, RCIC Injection”. Although the projected 80-year transient cycles numbers for transient numbers 27a and 27b exceed twice the number originally assumed, the overall effect of these transients on bulk reactor coolant temperature and fatigue damage to reactor vessel internals is insignificant. HPCI and RCIC flow is injected into the reactor vessel through the feedwater lines and not directly into the vessel. The resulting thermal stresses on the vessel internal components are negligible. For example, evaluation of the Unit 3 event on September 15, 2003, which resulted in over 50 RCIC or HPCI injections over a 22-hour time period, shows that these multiple injections resulted in only two significant reactor coolant temperature swings during the entire event.

The PBAPS EPU and MUR license amendment submittals also reported negligible 40-year and 60-year CUFs for the following components: Control Rod Drive Housing, Control Rod Guide Tube, Orificed Fuel Support, Shroud Head and Steam Separator Assembly (including Shroud

Head Bolts), Access Hole Cover, In-Core Housing and Guide Tube, and Core Differential Pressure and Liquid Control Line. CUF's for these components for 80-years are significantly less than 1.0.

Section 4.3.6.2 describes how the "Shroud" component 80-year CUF value was determined.

All 80-year CUF values are projected to remain less than the acceptance criterion of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) - The PBAPS reactor vessel internals generic fatigue analyses have been successfully satisfactorily projected through the second period of extended operation.

Table 4.3.6.1-1
Generic Reactor Vessel Internals CUF Values Applied To PBAPS Units 2 and 3

Reactor Vessel Internal Component	40-Year CUF Value	60-Year CUF Value	80-Year CUF Value
Shroud	0.593	0.89	0.89 (Note 1)
Core Plate	<0.1	<0.1	<0.2
Top Guide	0.435	0.65	0.87
Jet Pump (Riser Brace)	0.14	0.22	0.28
Core Spray Line (in-vessel)	0.167	0.25	0.334
Core Spray Sparger	0.20	0.30	0.40
Feedwater Sparger	0.32	0.48	0.64

Note 1: Refer to Section 4.3.6.2.

4.3.6.2 GENERIC BWR FATIGUE ANALYSES FOR THE CORE SHROUD

TLAA Description:

The PBAPS Extended Power Uprate (EPU) license amendment submittal to the NRC in 2012 (Reference 4.8.70) and the Measurement Uncertainty Recapture (MUR) Power Uprate license amendment submittal to the NRC in 2017 (Reference 4.8.57) documented generic BWR fleet 40-year and 60-year CUF values of 0.593 and 0.89 respectively for the reactor vessel core shroud. These generic CUF values were used in the two PBAPS submittals to the NRC to demonstrate that the PBAPS core shrouds are structurally qualified for operation in the EPU and MUR operating conditions for a 60-year plant life.

The generic design 40-year CUF value was generated by GEH in a generic BWR fleet fatigue analysis which assumed generic upset transients and numbers of transient cycles. The generic 60-year CUF value was calculated by GEH by multiplying the original 40-year design CUF values by 1.5.

Since the generic analysis was used to demonstrate that the PBAPS core shrouds are structurally qualified for EPU and MUR conditions for 60 years, it was identified as TLAA that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

The 40-year GEH generic fatigue evaluation, which was intended to bound all BWR/4 and BWR/5 plant shrouds used a worst-case approach to define the geometry, thermal, and mechanical stresses, and assumed the following transients:

1) 15 cycles of Cooldown - Loss of AC Power Natural Circulation Restart events;
2) 10 cycles of Cooldown - LPCI During Vessel Startup & Shutdown events; and
3) 10 cycles of Operational Basis Earthquake (OBE) events.

Events 1 and 2 above are not specified on the PBAPS Reactor Thermal Cycle Diagrams, and were not originally a part of the PBAPS CLB.

Events 1 and 2 result in the majority (approximately 95 percent) of the 40-year CUF value of 0.593. For events 1 and 2, the generic BWR fatigue analyses assumed reactor vessel and low pressure coolant injection (LPCI) system configurations that are different from the PBAPS configurations. The generic BWR fatigue analysis assumed that cold (40°F) LPCI fluid is injected directly into the reactor vessel and on to the core shroud via an assumed LPCI reactor vessel nozzle located in the reactor vessel beltline region. This configuration is applicable to newer vintage BWRs. However, the PBAPS reactor vessels do not have LPCI nozzles.

At PBAPS, LPCI flow is injected into the reactor recirculation loop piping by the residual heat removal (RHR) pumps, so it is not directly injected into the reactor vessel. At PBAPS, LPCI is an operating mode of the RHR system and is an engineered safeguard system. LPCI is actuated by conditions indicating a breach in the nuclear system process barrier, but water is delivered to the reactor core only after reactor vessel pressure is reduced. The RHR pumps have a maximum design discharge pressure of 450 psig, are interlocked so the pumps cannot inject at greater reactor pressures, and therefore cannot inject fluid into the reactor recirculation loops during normal plant operations. Therefore, at PBAPS, the potentially colder LPCI/RHR injection fluid will mix with hotter reactor coolant in the recirculation loop piping before it enters the reactor vessel through the recirculation inlet nozzles and jet pumps and is pumped into the reactor vessel lower head region below the shroud support. The resulting thermal stresses on the core shroud are negligible compared to those predicted in the GEH generic fatigue analyses based on 40°F fluid impinging directly on to the core shroud. Therefore, the generic GEH core shroud fatigue analysis represents very conservative results with respect to alternating stresses acting on the PBAPS core shroud during a LPCI injection, and very conservative results with respect to cumulative fatigue. Review of the PBAPS reactor vessel configuration shows that there are no other nozzles in the beltline region that could result in similar thermal transients to the core shroud.

PBAPS Units 2 and 3 have not experienced any cycles of Events 1 or 2 as of May 2017. Therefore, it is not credible that either PBAPS unit will experience 15 cycles of Event 1 and 10 cycles of Event 2 over the remaining time during the 80-year operating period.

With respect Event 3 (OBE), the PBAPS site has not experienced an OBE event as of May 2017. Therefore, it is not credible that the PBAPS site will experience 10 OBE events over the remaining time during the 80-year operating period of either unit.

For these reasons, the 60-year generic CUF values are conservative for 80 years of operation for both PBAPS units.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The generic reactor vessel core shroud generic fatigue analysis is applicable for PBAPS for 80 years of operations and remains valid through the second period of extended operation.

4.3.6.3 CORE SHROUD SUPPORT FATIGUE ANALYSIS REEVALUATION

TLAA Description:

As discussed in Section 4.3.2 of the first PBAPS License Renewal Application, (Reference 4.8.58) the core shroud support fatigue analysis was reevaluated in 1998 for the effects of increased recirculation pump starts with the recirculation loops outside of their thermal limits (Table 4.3.1-1 and 4.3.1-2, Transient 18). The reevaluation assumed the following transient cycles and number of transient cycles:

1) 40 cycles of “Sudden Start of Pump in Cold Recirculation Loop” (Table 4.3.1-1 and 4.3.1-2, Transient 18), this transient was added in the reevaluation;

2) 10 cycles of “Scram – Loss of Feedpumps – Isolation Valves Close” (Table 4.3.1-1 and 4.3.1-2, Transient 11);

3) 216 cycles of “Startup and Heatup (100ºF/hr. max)” (Table 4.3.1-1 and 4.3.1-2, Transient 3); and

4) 130 cycles of “Design Hydrostatic Test to 1,250 psig” (Table 4.3.1-1 and 4.3.1-2, Transient 2).

Based on these assumed transient cycles and numbers of transient cycles, the reevaluation conservatively computed a CUF of 0.834. As identified in Table 4.3.1-3, locations 22 and 23, EAF analysis was also performed for this component to develop subsequent CUF_{en} values.

Since this analysis was identified as a TLAA for the first license renewal project, it represents the CLB for the core shroud support and must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

The first PBAPS License Renewal Application committed to enhancing the Fatigue Monitoring (B.3.3.1) program to include automated transient cycle counting and tracking of fatigue CUFs. As a result, PBAPS installed the SI:FatiguePro^{TM} software, which included two bounding locations representing low alloy steel and nickel alloy materials in the “Shroud Support, Baffle Plate to Vessel Junction” (Table 4.3.1-3, location numbers 22 and 23). These locations are bounding with respect to the Core Shroud Support and monitor the cumulative fatigue usage associated with the Core Shroud Support Fatigue Analysis Reevaluation TLAA.

Table 4.3.1-3 illustrates that the projected 80-year CUF_{en} values associated with the bounding locations are projected to remain below the acceptance criterion of 1.0. The Fatigue Monitoring (B.3.1.1) program will monitor the bounding locations and ensure corrective action is taken prior to CUF_{en} for the core shroud support exceeding the acceptance criterion of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The Fatigue Monitoring (B.3.1.1) program is credited with managing the Core Shroud Support Fatigue Analysis Reevaluation TLAA through the second period of extended operation.

4.3.6.4 JET PUMP DIFFUSER/CORE SHROUD SUPPORT PLATE FATIGUE ANALYSIS

TLAA Description:
Section 4.3.2 of the first PBAPS License Renewal Application (Reference 4.8.58) documented a 40-year CUF value of 0.35 and a 60-year CUF value of 0.525 for the “Jet Pump Diffuser/Core Shroud Support Plate."

The fatigue evaluation of the “Jet Pump Diffuser/Core Shroud Support Plate” assumed the following transient cycles and number of transient cycles:

1) 5 cycles of “Sudden Start of Pump in Cold Recirculation Loop” (Table 4.3.1-1 and 4.3.1-2 Transient 18);

2) 114 cycles of “Startup and Heatup (100ºF/hr. max)” (Table 4.3.1-1 and 4.3.1-2 Transient 3);

3) 16 cycles of “HPCI Injections” (Table 4.3.1-1 and 4.3.1-2 Transient 27a); and

4) 1 DBA” (faulted condition).

Since the first License Renewal Application projected a 60-year CUF, this projection represents a TLAA that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:
The first PBAPS License Renewal Application committed to enhancing the Fatigue Monitoring program to include automated transient cycle counting and automated calculation and tracking of fatigue CUFs. As a result, PBAPS installed the SI:FatiguePro™ software, which included a bounding location for the “Jet Pump Shroud Support, Diffuser Weld to Baffle Plate” (Table 4.3.1-3 bounding location number 24). This bounding location will monitor the cumulative fatigue usage associated with the Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis TLAA.

Table 4.3.1-3 illustrates that projected 80-year CUF_{en} value associated with bounding location number 24 will remain below the acceptance criterion of 1.0. The Fatigue Monitoring program will monitor this bounding location and ensure corrective action is taken prior to exceeding the acceptance criterion of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The Fatigue Monitoring (B.3.1.1) program is credited with managing the Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis TLAA through the second period of extended operation.

4.3.6.5 REPLACEMENT STEAM DRYER STRESS REPORT AND FATIGUE EVALUATION

TLAA Description:

The reactor pressure vessel steam dryers have been replaced on each PBAPS unit to support the Extended Power Uprate (EPU) project. The new steam dryers were evaluated in 2014 in accordance with the requirements of ASME Section IIII, Division I, Subsection NG, "Core Support Structure", 2007 Edition with 2008 Addenda. The evaluation concluded that the maximum CUF for all applicable normal operating loads, which considered 1380 turbine stop valve transient cycles, 400 startup and shutdown transient cycles, and one OBE event with 63 stress cycles concurrent with flow induced vibration (FIV) and recirculation pump vane passing frequency (VPF), is 0.0015 compared to the ASME CUF limit of 1.0.

Since the evaluation resulted in a calculated CUF value using assumed transient cycle inputs, it has been identified as TLAA that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

The fatigue evaluation concluded that alternating stresses associated with FIV and VPF are well below the ASME endurance limits. Therefore, the primary contributors to the design CUF value of 0.0015 are the 400 startup and shutdown transient cycles and the one OBE event with 63 stress cycles. The turbine stop valve transient cycles are not significant contributors to fatigue since these transient cycles do not result in significant temperature changes to the steam dryers.

Table 4.3.1-1 and 4.3.1-2 provide 80-year transient cycle projections based on past transient cycle accumulation through December 31, 2015. Table 4.3.1-1 shows that Unit 2 is projected to experience 186 "Heatup-Cooldown" (transient 3) cycles and one OBE (transient 31) event for the 80-year second license renewal period. Table 4.3.1-2 shows that Unit 3 is projected to experience 140 "Heatup-Cooldown" (transient 3) cycles and one OBE (transient 31) event for the 80-year second license renewal period. These projections, which include the actual number of transients that occurred prior to the installation of the new steam dryers, are bounded by the 1380 turbine stop valve transient cycles, 400 startup and shutdown transient cycles and one OBE event assumed in the replacement steam dryer evaluation. Therefore, the replacement steam dryer evaluation remains valid for 80 years of operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The replacement steam dryer fatigue evaluation remains valid through the second period of extended operation.

4.3.7 HIGH-ENERGY LINE BREAK (HELB) ANALYSES BASED ON CUMULATIVE FATIGUE USAGE

TLAA Description:

High Energy Line Break (HELB) analyses for the PBAPS recirculation system piping use the CUF values from the ASME Section III Class 1 fatigue analyses as input in determining intermediate break locations. Locations with a CUF value less than or equal to 0.1 do not require an intermediate break to be postulated. Since the HELB analyses are based on the Class 1 piping fatigue TLAAs that provided the CUF values, they have also been identified as TLAAs.

TLAA Evaluation:

A high energy line break is not required to be postulated at a given location if the design CUF calculated in accordance with ASME Section III, for that location, is less or equal to 0.1. The recirculation system piping fatigue analyses described in Section 4.3.2 are the source for the calculated design CUF values which were used in the HELB break exclusion evaluations. The fatigue analyses in Section 4.3.2 are based on the transient cycles listed in Tables 4.3.1-1 and 4.3.1-2.

As described in Section 4.3.1, the Fatigue Monitoring (B.3.1.1) program uses SI:FatiguePro™ 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.

All potential break locations have been evaluated and the SI:FatiguePro™, “Recirculation Piping and RHR Return Line” bounding location was determined to be most limiting HELB break exclusion location. Table 4.3.1-3, location 6, shows that this bounding location is projected to remain less than 0.1 through the end of second period of extended operation. Therefore, all original excluded locations will continue to meet the break exclusion criterion and there are no new break locations postulated.

In order to ensure the projected “Recirculation Piping and RHR Return Line” bounding location CUF value in Table 4.3.1-3 will not exceed the HELB break exclusion acceptance criterion, the Fatigue Monitoring program will be enhanced to add an HELB CUF acceptance criterion of 0.1 for this bounding location. The program administrative requirements will ensure that corrective action is taken prior to a recirculation system piping location CUF exceeding the HELB break exclusion acceptance criterion.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The recirculation system piping fatigue analyses used as input to the HELB analyses will be managed by the Fatigue Monitoring (B.3.1.1) program through the second period of extended operation.

4.3.8 INSERVICE 60-YEAR RPV CLOSURE HEAD WELD FLAW ANALYSES

TLAA Description:

This section describes three separate flaw evaluations performed on PBAPS Units 2 and 3 reactor pressure vessel (RPV) closure head welds.

PBAPS Unit 3 RPV Closure Head Welds CH-MA, CH-MC, and CH-MF

During the 2001 refueling outage, routine inservice inspection (ISI) volumetric examinations were performed on the Unit 3 RPV closure head meridional welds. These examinations identified indications in three meridional welds, CH-MA, CH-MC, and CH-MF. Nine of these indications did not meet the acceptance criteria in ASME Section XI, 1989 Edition (without Addenda), Table IWB-3510-1. Subsequently General Electric (GEH) performed an evaluation of the flaws in accordance with ASME Section XI Subsection IWB-3600 and Appendix A.

Prior to the 2001 refueling outage a review of the fabrication and inspection history of these welds revealed that these indications had existed since fabrication, had previously been identified in prior ISI examination, and it was expected that they would most likely be rejected when examined in 2001 under the new Performance Demonstration Initiative (PDI).

GEH evaluated the fatigue crack growth of the indications applying assumed plant transient cycles based on the original 40-year cycle limits multiplied by 1.5. The cycles that were assumed for the crack growth evaluation were: 1) 100 “Bolt-Up” transient cycles, 2) 195 “Hydrostatic Test” transient cycles, and 3) 245 “Heatup-Cooldown” transient cycles. These inputs were conservative since they ignored actual cycles that had occurred on the Unit 3 RPV closure head prior to 2001.

The evaluation concluded that the limiting indication was acceptable per ASME Section XI, even after accounting for projected crack growth for the life of the plant including the period of extended operation (60 total years).

Since the GEH evaluation assumed a number of plant transient cycles over the 60-year life of the plant, the evaluation is a TLAA which must be evaluated for 80 years.

PBAPS Unit 2 RPV Closure Head Weld CH-MB

During the 2002 refueling outage, routine inservice inspection (ISI) examinations were performed on the Unit 2 RPV closure head meridional welds. These examinations identified 18 indications in one of the meridional welds, CH-MB. Sixteen of these indications did not meet the acceptance criteria in ASME Section XI Table IWB-3510-1. Subsequently GEH performed an evaluation of these flaws in accordance with ASME Section XI Subsection IWB-3600 and Appendix A.

Prior to the 2002 refueling outage a review of the fabrication and inspection history revealed that these indications had existed since fabrication, had previously been identified, and it was expected that they would most likely be rejected when examined in 2002 under the new Performance Demonstration Initiative (PDI).

GEH evaluated the fatigue crack growth of the indications applying assumed plant transient cycles based on the original 40-year cycle limits multiplied by 1.5. The cycles that were assumed for the crack growth evaluation were: 1) 100 “Bolt-Up” transient cycles, 2) 195 “Hydrostatic Test” transient cycles, and 3) 245 “Heatup-Cooldown” transient cycles. These inputs were conservative since they ignore actual cycles that had occurred on the Unit 2 RPV closure head prior to 2002.

The evaluation concluded that the limiting indication was found to be acceptable per ASME Section XI, even after accounting for projected crack growth for the life of the plant including license renewal (60 total years).

Since the GEH evaluation assumed a number of plant transient cycles over the 60-year life of the plant, the evaluation is a TLAA which must be evaluated for 80 years.

PBAPS Unit 2 RPV Closure Head Welds CH-C-2

During the 2010 refueling outage, routine inservice inspection (ISI) examinations were performed on the Unit 2 RPV closure head to flange weld. These examinations identified indications in the closure head to flange weld, CH-C-2. All but one of these indications met the acceptance criteria in ASME Section XI Table IWB-3510-1. The remaining indication did not meet the acceptance criteria in ASME Section XI Table IWB-3510-1. Subsequently GEH performed an evaluation of this indication in accordance with ASME Section XI Subsection IWB-3600 and Appendix A.

The GEH analysis compared the indication found in weld CH-C-2 in 2010 to the fatigue crack growth evaluation performed on the Unit 2 CH-MB weld in 2002 (Reference 4.8.69). This evaluation is described above. The 2010 GEH analysis concluded that the crack growth rate determined in the 2002 GEH evaluation is conservative and could be applied to the CH-C-2 indication found in 2010. The 2010 evaluation concluded that the indication found in 2010 on the CH-C-2 weld, even after accounting for projected crack growth for the 60-year life of the plant, is acceptable for continued operation using the evaluation acceptance criteria of ASME Section XI Code.

Since the 2010 evaluation used a fatigue crack growth rate evaluation which assumed a number of plant transient cycles over the 60-year life plant, the evaluation is a TLAA which must be evaluated for 80 years.

TLAA Evaluation:

Each of the three analyses are based on the same assumed transient cycles and transient cycle numbers as follows: 1) 100 “Bolt-Up” transient cycles, 2) 195 “Hydrostatic Test” transient cycles, and 3) 245 “Heatup-Cooldown” transient cycles. These assumptions were conservative since they ignore actual cycles that had occurred prior to the 2001, 2002, and 2010 inspections.

Tables 4.3.1-1 and 4.3.1-2 provide 80-year transient cycle projections based on the number of past transient cycles up to December 31, 2015, extrapolated to the end of the 80-year second period of extended operation. Table 4.3.1-1 shows that Unit 2 is projected to experience: 74 “Bolt-Up” (transient 1); 55 “Hydrostatic Test” (transient 2); and 186 “Heatup-Cooldown” (transients 3 and 21) transient cycles over the 80-year period. For Unit 3, Table 4.3.1-2 shows that the projected number of transient cycles over 80 years is: 77 “Bolt-Up” (transient 1); 52 “Hydrostatic Test” (transient 2); and 140 “Heatup-Cooldown” (transients 3 and 21) transient cycles over the 80-year period. For all three transients, the number of transient cycles projected for the 80-year period is less than the number of transient cycles assumed in the 60-year analyses. Therefore, transient cycle numbers that were assumed for 60 years in the original analyses remain valid for the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The three TLAAs for flaw evaluations performed on PBAPS Units 2 and 3 RPV closure head welds remain valid through the second period of extended operation.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

4.4.1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description:

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs) for PBAPS. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Environmental Qualification Program Background

The Environmental Qualification of Electric Equipment (B.3.1.3) program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected. The environmental qualification of Class 1E equipment at PBAPS has been reviewed against the NRC Division of Operating Reactors' "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" which was an enclosure to IE Bulletin 79-01B, dated January 14, 1980.

Aging evaluations for electrical components in the Environmental Qualification of Electric Equipment program that specify a qualification of at least 60 years are TLAAs for the second license renewal because the criteria contained in 10 CFR 54.3 are met.

TLAA Evaluations

Under 10 CFR 54.21(c)(1)(iii), the Environmental Qualification of Electric Equipment (B.3.1.3) program, which implements the requirements of 10 CFR 50.49 (as further defined and clarified by the NRC Division of Operating Reactors' "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" which was an enclosure to IE Bulletin 79-01B, dated January 14, 1980), is an aging management program for License Renewal.

Reanalysis of an aging evaluation to extend the qualifications of components is performed as part of the Environmental Qualification of Electric Equipment program. The program complies with all applicable regulations and manages equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, ongoing qualification, and corrective actions (if acceptance criteria are not met). Environmentally qualified equipment must be refurbished, replaced, or have its qualification extended prior to reaching the aging limits established in the aging evaluation.

TLAA demonstration to option 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the second period of extended operation, is chosen and the Environmental Qualification of Electric Equipment program will manage the aging effects of the components associated with the environmental qualification TLAA.

NUREG-2191 states that the Staff evaluated the EQ program based on 10 CFR 50.49, and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii).

The evaluation referred to in the Standard Review Plan - SLR (NUREG-2192) contains sections on “EQ Component Reanalysis Attributes, Evaluation, and Technical Basis” that is the basis of the description provided below.

Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism, or applying more accurate location specific conditions, that were not incorporated in the prior evaluation. 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 program. While a component life-limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the design ambient versus measured ambient temperature, unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to PBAPS quality assurance program requirements, which require the verification of assumptions and conclusions. As already 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 program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal 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, which is the normal radiation dose for the projected installed life plus accident radiation dose. For second license renewal, one acceptable method of establishing the 80-year normal radiation dose is to multiply the 60-year normal radiation dose by 1.33 (that is, 80 years/60 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 & Reduction Methods

The chief method used for a reanalysis per the Environmental Qualification of Electric Equipment program is reduction of excess conservatism in the component service conditions used in the prior aging evaluation, including temperature, radiation, and cycles. Temperature data used in an aging evaluation should be based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors. A representative number of temperature measurements are evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as: (a) directly applying the plant temperature data in the evaluation; or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis must be justified. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging. Operating Experience can also provide additional basis to justify changes in the qualification of the equipment.

Underlying Assumptions

The Environmental Qualification of Electric Equipment program component aging evaluations contain sufficient conservatism. Additionally, plant modifications that have potential impact to the Environmental Qualification of Electric Equipment program are evaluated during the modification design process to determine the impact of the plant modification on the Environmental Qualification of Electric Equipment program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action

Under the Environmental Qualification of Electric Equipment program, the reanalysis of an aging evaluation could extend the qualified life 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. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful.

Ongoing Qualification

Under the Environmental Qualification of Electric Equipment program, 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 second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be adequately managed through the second period of extended operation by the Environmental Qualification of Electric Equipment (B.3.1.3) program.

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS

4.5.1 The PBPAS containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

4.6 PRIMARY CONTAINMENT FATIGUE ANALYSES

The fatigue analyses for following PBAPS Unit 2 and Unit 3 primary containment structures, penetrations, and associated components have been identified as TLAAs and require evaluation for the second period of extended operation:

- Unit 2 and Unit 3 Torus Shell (Section 4.6.1)
- Unit 2 and Unit 3 Torus Penetrations (Section 4.6.1)
- Unit 2 and Unit 3 Drywell-to-Torus Vents (Section 4.6.1)
- Safety Relief Valve (SRV) Discharge Piping (Section 4.6.1)
- Other Piping Attached to Torus (Section 4.6.1)
- Drywell-to-Torus Vent Bellows (Section 4.6.1)
- Replacement RHR and Core Spray Suction Strainers (Section 4.6.1)
- Containment Process Line Penetration Bellows (Section 4.6.2)

The following PBAPS Unit 2 and Unit 3 primary containment structures, penetrations, and associated components were determined not to have an existing fatigue analysis and therefore have no fatigue TLAAs:

- Drywell Shell
- Drywell Head
- Drywell Personnel Airlock
- Drywell Equipment Hatches
- Drywell CRD Removal Hatch
- Drywell Electrical Penetrations
- Drywell Mechanical Penetrations

The original design for the Primary Containment for both units was in accordance with ASME Section III, Subsection B, 1965 Edition with addenda through the Summer of 1966, which did not require an evaluation of fatigue.

4.6.1 PRIMARY CONTAINMENT STRUCTURES, PENETRATIONS, AND ASSOCIATED COMPONENTS WITH FATIGUE ANALYSES

TLAA Description:

Subsequent to the original design, elements of the PBAPS Units 2 and 3 primary containments were reanalyzed in response to discoveries, by General Electric and others, of unevaluated loads due to design basis events and Safety Relief Valve (SRV) discharge. The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge and design basis loss of coolant accident (LOCA) events. Components of the Primary Containment that were analyzed included the torus shell, torus penetrations, the drywell-to-torus vent piping, SRV discharge piping, other piping attached to the torus, and the drywell to torus vent bellows (Reference 4.8.63). As such, these components were analyzed for fatigue and are considered TLAAs.

In 1997 and 1998 PBAPS Units 2 and 3 replaced the RHR and Core Spray System suction strainers. These new strainers and their supports were designed to ASME Section III Subsections NC, NE, and NF 1980 edition up to and including Winter 1981 Addenda. As such, the new strainers and supports were analyzed for fatigue and are considered TLAAs.

The following Unit 2 and Unit 3 primary containment structures, torus penetrations, and associated components have been analyzed for fatigue and have been identified as TLAAs that require evaluation for the second period of extended operation:

- Unit 2 and Unit 3 Torus Shell
- Unit 2 and Unit 3 Torus Penetrations
- Unit 2 and Unit 3 Drywell-to-Torus Vents
- Unit 2 and Unit 3 Safety Relief Valve (SRV) Discharge Piping
- Unit 2 and Unit 3 Other Piping Attached to the Torus
- Unit 2 and Unit 3 Drywell-to-Torus Vent Bellows
- Unit 2 and Unit 3 Replacement RHR and Core Spray Suction Strainers

TLAA Evaluation:

The primary containment fatigue reanalysis and the suction strainer analyses used, as input, the following transient cycles:

- SRV Lifts (Tables 4.3.1-1 and 4.3.1-2 transient 29)
- Safe Shutdown Earthquake (Tables 4.3.1-1 and 4.3.1-2 transient 32)
- Operating Basis Earthquake (Tables 4.3.1-1 and 4.3.1-2 transient 31)
- Chugging during a LOCA (Tables 4.3.1-1 and 4.3.1-2 transient 34)

Of these, the SRV lift transient is the only transient that is associated with normal operations while the remaining transients are either faulted or upset events. Each of the associated fatigue analysis assumed at least 800 SRV lift transient cycles, which remain the 80-year projection and exceed by more than an order of magnitude the number of such transient cycles that have occurred to date.

The following are the resulting bounding design CUF values from these analyses:

- Unit 2 and Unit 3 Torus Shell
  - Design CUF of 0.942 for the junction of the shell and ring girder.
- Unit 2 and Unit 3 Torus Penetrations
  - Design CUF of 0.992 for the limiting torus penetration.
- Unit 2 and Unit 3 Drywell-to-Torus Vents
  - Design CUF of 0.942 for the junction of the vent header and the downcomer.
- Unit 2 and Unit 3 Safety Relief Valve (SRV) Discharge Piping
  - Design CUF of 0.202 for SRV discharge lines.
- Unit 2 and Unit 3 Other Piping Attached to the Torus
  - Design CUF of 0.202 for Torus Attached Piping.
- Unit 2 and Unit 3 Drywell-to-Torus Vent Bellows
  - Negligible design CUF for the bellows.
- Unit 2 and Unit 3 Replacement RHR and Core Spray Suction Strainers
  - Design CUFs of 0.193, 0.367, and 0.432 for various sub components on the Units 2 and 3 strainer elements and a design CUF of 0.661 for Units 2 and 3 strainer support elements welded to the torus shell.

The Fatigue Monitoring (B.3.1.1) program is credited with managing primary containment structures, penetrations, and associated components TLAAs. The Fatigue Monitoring program currently uses SI:FatiguePro™ to monitor fatigue of the bounding primary containment component locations, computing the CUF-to-date values based upon the cumulative numbers of fatigue transient cycles that have occurred as of the monitoring date. During implementation of SI:FatiguePro™, a review of containment fatigue analyses was performed to select the bounding locations for monitoring. The following SI:FatiguePro™ locations bound the above components for both Unit 2 and Unit 3:

- Torus (CS)/Torus Shell (Table 4.3.1-3, location 26)
- Torus Penetrations (CS)/ Torus Shell (Table 4.3.1-3, location 27)

Since the remaining primary containment components are affected by the same transient cycles as these bounding locations, and the remaining locations have the same or lower design fatigue usage, the remaining primary containment components will not exceed the limit of 1.0, as long as the monitored locations do not exceed the limit. The Fatigue Monitoring program includes requirements that initiate corrective actions if a CUF value exceeds 80 percent of the ASME Section III acceptance criterion.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The Fatigue Monitoring (B.3.1.1) program is credited with managing these primary containment fatigue TLAAs through the second period of extended operation.

4.6.2 CONTAINMENT PROCESS LINE PENETRATION BELLOWS

TLAA Description:

PBAPS Units 2 and 3 process lines that penetrate the primary containment and experience significant thermal expansion and contraction were designed with penetration bellows. The following process lines were designed with penetration bellows: the main steam lines, the feedwater lines, the HPCI steam line, the RHR supply and return lines, the RWCU pump suction line, the core spray discharge lines, and the vessel head spray line. The Unit 3 RHR supply and return line penetration bellows were replaced during 1988 and 1989 recirculation and RHR system piping replacement project.

The original primary containment penetration bellows were designed to ASME Section III, 1968, Appendix IX-200, Class B Vessels and Codes Cases 1177-5 and 1330-1. The design specification for the original bellows specified 200 “startup-shutdown” cycles (as defined in Section III) and a minimum of 1,500 “normal operating” cycles (as defined in Section III). In addition, the design specification provided the maximum axial compression and lateral offsets that bounded these transient cycles. ASME Section III defines that a startup-shutdown cycle is one in which the bellows experience temperature and pressure increases from ambient to normal operating temperature and pressure (150°F and 2 psig). In addition, ASME Section III defines that; a “normal operating cycle” is “any cycle between startup and shutdown required for the vessel to perform its intended function”. Therefore a “normal operating cycle” as defined in ASME Section III is one in which the bellows experience temperature and pressure increases from 150°F and 2 psig to 281°F and 56 psig, as is postulated during a design basis accident (DBA).

The Unit 3 RHR system replacement penetration bellows were designed to ASME Section III, 1980 Edition with Winter 1981 Addenda, Section NC-3649.4. The design specification for the replacement penetration bellows specified 1,500 normal operating cycles, from 150°F and 2 psig to 281°F and 56 psig, and the associated maximum axial and lateral offsets. The design specification for the replacement penetration bellows did not specify 200 startup-shutdown cycles.

As such, these primary containment bellows were analyzed for fatigue and are considered TLAAs.

TLAA Evaluation:

Tables 4.3.1-1 and 4.3.1-2 provide 80-year transient cycle projections based on the number of past transient cycles as of December 31, 2015, extrapolated to the end of the 80-year second period of extended operation. These tables show that Units 2 and 3 are projected to experience 186 and 140 “Heatup-Cooldown” transient cycles over the 80-year period respectively, which are less than the specified 200 startup-shutdown transient cycles for the original containment bellows. Therefore, for both the original and replaced containment bellows, the specified 1500 “normal operating cycles” associated with a DBA is significantly greater than an assumed one DBA per unit over an 80-year period.

Therefore, the transient cycle numbers that were assumed for 40 years in the original analyses are valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The primary containment process line bellows fatigue analyses remain valid through the second period of extended operation.

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

This section evaluates:

- Reactor Building Crane Cyclic Loading Analysis (Section 4.7.1)
- Emergency Diesel Generator Bridge Crane Cyclic Loading Analysis (Section 4.7.1)
- Turbine Building Crane Cyclic Loading Analysis (Section 4.7.1)
- Circulating Water Pump Structure Crane Cyclic Loading Analysis (Section 4.7.1)
- Reactor Vessel Main Steam Nozzle Clad Removal Corrosion Allowance (Section 4.7.2)
- Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking” (Section 4.7.3)
- Fracture Mechanics of ISI-Reportable Indications for Group I Piping: As-forged laminar tear in a Unit 3 Main Steam elbow near weld 1-B-3BC-LDO discovered during preservice UT (Section 4.7.4)
- Unit 3 Core Spray Replacement Piping Leakage Assessment (Section 4.7.5)

4.7.1 CRANES CYCLIC LOADING ANALYSES

TLAA Description:

A review of design specifications for cranes within the scope of second license renewal was performed to identify those cranes that were designed or meet the intent of Crane Manufacturers Association of America (CMAA) Specification 70 (Reference 4.8.47). As documented in UFSAR Section 10.4.10, "Reactor Building Crane" and UFSAR Section 10.4.11, "Heavy Loads Compliance", the PBAPS reactor building cranes, emergency diesel generator bridge cranes, turbine building cranes, and circulating water pump structure crane meet the intent of Chapter 2-1 of ANSI B30.2-1976, "Overhead and Gantry Cranes" and the CMAA Specification 70. CMAA Specification 70 includes considerations for frequency of operation and expected load sizes relative to their maximum load capacity. Based on these considerations, cranes are designed for a given service class classification with an expected maximum number of design load cycles over their life, which also correlates to a number of load cycles on structural members. The service class is used to define the allowable stress range limits for structural members and fasteners to consider the fatigue resulting from cyclic operation over the life of the crane.

Since the maximum number of load cycles over the life of the cranes, specified in CMAA Specification 70, provides a basis for acceptability for fatigue over the life of these cranes, these analyses are considered TLAAs that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

Reactor Building Cranes

Each PBAPS unit has a reactor building crane that is within the scope of license renewal. The design specifications document that the reactor building cranes are rated for 125 tons and are designated as "Class A" (Standby Service). Referring to Table 2.8-1 of CMAA Specification 70, Class A cranes experience "irregular occasional use followed by long idle periods." For these cranes, the CMAA design considerations allow for between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative limitation on load cycles for these cranes and is considered acceptance criterion for this TLAA. Load cycles that lift less than 50 percent of the crane design capacity of 125 tons (62.5 tons) result in minimal fatigue of the crane. Therefore, load cycles that lift 50 tons or more are evaluated.

Table 4.7.1-1 provides the 80-year projections for reactor enclosure crane load cycles. The number of cycles projected for 80 years of operation is 4,032 cycles for each crane.

The 80-year projected number of cycles is approximately 20 percent of the minimum allowable design value of 20,000 cycles and therefore the acceptance criterion is met. Therefore, the fatigue analysis for the reactor building cranes remains valid for 80 years of plant operation.

Emergency Diesel Generator Bridge Cranes

Each of the four Emergency Diesel Generator rooms within the Emergency Diesel Generator Building has a bridge crane that is within the scope of license renewal. The design specifications document that these cranes are rated for 15 tons and are designated as "Class A" (Standby Service). Referring to Table 2.8-1 of CMAA Specification 70, the emergency diesel generator bridge cranes are Class A cranes experience "irregular occasional use followed by long idle periods." For these cranes, the CMAA design considerations allow for between 20,000 and

100,000 load cycles. Therefore, 20,000 load cycles is a conservative limitation on load cycles for these cranes and is considered acceptance criterion for this TLAA. Load cycles that lift less than 50 percent of the crane design capacity of 15 tons (7.5 tons) result in minimal fatigue of the crane. Therefore, load cycles that lift 6 tons or more are evaluated.

A conservative estimate, as determined from review of station procedures and personnel knowledgeable on the use of these cranes, results in approximately 4,500 load cycles through the second period of extended operation. The estimate for each crane is based on an estimated 500 load cycles during original construction and 50 load cycles per year during diesel generator maintenance. The number of cycles projected for 80 years of operation is 4,500 cycles for each bridge crane.

The 80-year projected number of cycles is less than 25 percent of the minimum allowable design value of 20,000 cycles and therefore the acceptance criterion is met. Therefore, the fatigue analysis for the emergency diesel generator bridge cranes remains valid for 80 years of plant operation.

Turbine Building Cranes

Each PBAPS unit has a turbine building crane that is within the scope of license renewal. The design specifications document that these cranes were originally rated for 115 tons and are designated as “Class A” (Standby Service). Referring to Table 2.8-1 of CMAA Specification 70, the turbine building cranes are Class A cranes experience “irregular occasional use followed by long idle periods.” For these cranes, the CMAA design considerations allow for between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative limitation on load cycles for this crane and is considered acceptance criterion for this TLAA. Load cycles that lift less than 50 percent of the crane design capacity of 115 tons (57.5 tons) result in minimal fatigue of the crane. Therefore, load cycles that lift 50 tons or more are evaluated.

Table 4.7.1-2 provides the 80-year projections for turbine building crane load cycles. The number of cycles projected for 80 years of operation is 7,340 cycles for each crane.

The 80-year projected number of cycles is less than 40 percent of the minimum allowable design value of 20,000 cycles and therefore the acceptance criterion is met. Therefore, the fatigue analysis for the turbine building cranes remains valid for 80 years of plant operation.

Circulating Water Pump Structure Crane

PBAPS has a common circulating water pump structure crane that is within the scope of license renewal. The design specifications document that this crane is rated for 35 tons and is designated as “Class A” (Standby Service). Referring to Table 2.8-1 of CMAA Specification 70, the circulating water pump structure crane is a Class A crane experience “irregular occasional use followed by long idle periods.” For this crane, the CMAA design considerations allow for between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative limitation on load cycles for this crane and is considered acceptance criterion for this TLAA. Load cycles that lift less than 50 percent of the crane design capacity of 35 tons (17.5 tons) result in minimal fatigue of the crane. Therefore, load cycles that lift 17 tons or more are evaluated.

Table 4.7.1-3 provides the 80-year projections for circulating water pump structure crane load cycles. The number of cycles projected for 80 years of operation is 1,780 cycles.

The 80-year projected number of cycles is less than 10 percent of the minimum allowable design value of 20,000 cycles and therefore the acceptance criterion is met. Therefore, the fatigue analysis for the circulating water pump structure crane remains valid for 80 years of plant operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The projected number of load cycles associated with reactor building cranes, emergency diesel generator bridge cranes, turbine building cranes, and circulating water pump structure crane are considerably less than the allowable design value. Therefore, the TLAAs remain valid through the second period of extended operation.

Table 4.7.1-1
PBAPS Unit 2 and Unit 3 Reactor Building Crane Load Cycles

Heavy Load Description	Frequency (Note 1)	Number of Years	Number of Lifts over 80 years
Plant Construction Cycles:			200
Reactor Vessel Head with strong back	2/year	80	160
Drywell Head with strong back	2/year	80	160
Steam Dryer	2 /year	80	160
Steam Separator	2/year	80	160
Shield Plugs (1 through10)	20/year	80	1600
Miscellaneous	4/year	80	320
Completed ISFSI Casks (2016) 40 Casks; 6 Lifts per Cask	NA	NA	240
Planned ISFSI Cask Load Cycles (2017 – 2019) 6 Lifts per Cask	4/year	3	72
Projected ISFSI Cask Load Cycles (2019 – 2054) 6 Lifts per Cask	4/year	35	840
Low Level Waste Cask Load Cycles (80-year Projection) 6 Lifts per Cask - 20 Casks over 80 Years	NA	NA	120
80-Year Total Load Cycles:			4,032
Minimum Design Limit			20,000
Percent of Load Cycle Limit at 80 Years:			20%

Note 1: Frequencies conservatively assume an annual refueling outage.

Table 4.7.1-2
PBAPS Unit 2 and Unit 3 Turbine Building Crane Load Cycles

Heavy Load Description	Frequency (Note 1)	Number of Occurrences	Number of Lifts over 80 years
Plant Construction Cycles			500
Generator Rotor with Lifting Beam	2/8 years	10	20
Generator Outer End Sections	2/8 years	10	20
Generator Rad Wall	2/4 years	20	40
Front Standard Rad Wall	2/4 years	20	40
HP Turbine Outer Shell (Lower)	2/4 years	20	40
HP Turbine Outer Shell (Upper)	2/4 years	20	40
HP Turbine Rotor	2/4 years	20	40
LP Turbine Exhaust Hood	2/2 years	40	80
LP Turbine Inner Casing	2/2 years	40	80
LP Turbine A Rotor	6/6 years	13.3	80
LP Turbine B Rotor	6/6 years	13.3	80
LP Turbine C Rotor	6/6 years	13.3	80
80-Year Total Load Cycles:			7,340
Minimum Design Limit			20,000
Percent of Load Cycle Limit at 80 Years			36.7%

Note 1: Frequencies conservatively assume recommended turbine and generator maintenance schedules.

Table 4.7.1-3
PBAPS Common Circulating Water Pump Structure Crane

Heavy Load Description	Frequency (Note 1)	Number of Years	Number of Lifts over 80 years
Plant Construction Cycles			500
Replace Circulating Water Pump (2 lifts per year per unit)	4/year	80	320
Replace Circulating Water Pump Motor (2 lifts per year per unit)	4/year	80	320
Replace Traveling Screens (2 lifts per year per unit)	4/year	80	320
Replace Sluice Gate (2 lifts per year per unit)	4/year	80	320
80-Year Total Load Cycles:			1,780
Minimum Design Limit			20,000
Percent of Load Cycle Limit at 80 Years			9%

Note 1: Frequencies conservatively based on operating experience.

4.7.2 REACTOR VESSEL MAIN STEAM NOZZLE CLAD REMOVAL CORROSION ALLOWANCE

TLAA Description:

An analysis performed in 1974 justified removal of the PBAPS Units 2 and 3 reactor vessel main steam nozzle cladding using a time-dependent corrosion rate over 40 years and a corrosion allowance as acceptance criteria. As such, the evaluation was identified as a TLAA in the first License Renewal Application (LRA) that must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

The evaluation concluded that a total general wall loss of 0.065 inches is an acceptable corrosion allowance for the reactor vessel main steam nozzles. Section 4.7.1 of the first PBAPS LRA documented that internal surfaces the reactor vessel main steam nozzles will only experience general wall loss of 0.030 inches over a 60-year period, which is significantly less than the corrosion allowance acceptance criterion of 0.065 inches. During review of PBAPS's first LRA, the NRC requested additional information related to the basis for the applied corrosion rate. In response Exelon provided the basis for the corrosion rate in Reference 4.8.65. In the NRC's SER for PBAPS's first LRA (Reference 4.8.59) the NRC concluded that: "Based on the applicant's conservative analysis of the predicted loss of material resulting from corrosion during 60 years of operation, the Staff concludes that the corrosion allowance identified when the clad was removed from the main steam nozzles is valid for 60 years of operation."

The previously provided general wall loss of 0.030 inches over a 60-year period results in a corrosion rate 0.0005 inches per year. Extrapolating the same corrosion rate through the end of the second period of extended operation results in an expected 80-year total general wall loss of 0.040 inches. Therefore, the projected 80-year corrosion loss remains significantly less than the corrosion allowance acceptance criterion of 0.065 inches.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) - The analysis of reactor vessel main steam nozzle corrosion allowance has been satisfactorily projected through the second period of extended operation.

4.7.3 GENERIC LETTER 81-11 CRACK GROWTH ANALYSIS TO DEMONSTRATE CONFORMANCE TO THE INTENT OF NUREG-0619, "BWR FEEDWATER NOZZLE AND CONTROL ROD DRIVE RETURN LINE NOZZLE CRACKING"

TLAA Description:

NUREG-0619 (Reference 4.8.51) was issued by the NRC per Generic Letter (GL) 81-11 in February 1981 (Reference 4.8.43) because of observed cracking on the inside surfaces of BWR feedwater nozzles at the blend radius and bore. The causes included: 1) on-off feedwater flow control at low power, 2) high clad thermal stresses, and 3) leakage between the nozzle and the thermal sleeve. In the original BWR designs the thermal sleeve was loosely fit into the feedwater nozzle bore. The leakage caused rapid thermal cycling, on the order of a few cycles per second, driven by convective instability in the mixing region. Such cracking was observed in the feedwater nozzles at PBAPS Units 2 and 3 early in each unit's life before 1980.

The cracks initiated by this rapid thermal cycling fatigue mechanism were shallow because the induced thermal stresses have steep gradients and shallow depth. These small internal cracks could potentially propagate to larger cracks by low cycle fatigue due to normal plant transients such as heatup, cooldown, and feedwater transients. Normal operational transients produce larger, through wall, stress cycles in the nozzle wall, and in time could drive the smaller internal cracks, already formed by the rapid thermal cycling fatigue mechanism, to continue to grow to depths for which the vessel fracture mechanics analyses would predict further growth through the vessel wall.

NUREG-0619 provided recommendations for plant modifications, to reduce or eliminate the rapid thermal cycling fatigue mechanism, and inspections that were intended to detect cracking prior to becoming large enough to become a safety issue.

In 1980 and 1981, the following three modifications recommended within NUREG-0619 were implemented on PBAPS Units 2 and 3 to reduce or eliminate the feedwater nozzle rapid thermal cycling fatigue cracking mechanism: (a) installation of improved nozzle triple thermal sleeves with dual piston ring seals, (b) removal of cladding from the nozzle bore and blend radii, and (c) improvement of the low-flow feedwater controllers. Also, the control rod drive return line (CRDRL) nozzles have been capped at PBAPS Units 2 and 3 to eliminate cracking due to rapid thermal cycling.

In addition, in 1983, augmented ISI inspections of the feedwater nozzles were implemented on PBAPS Units 2 and 3 based on the recommendations in NUREG-0619. The inspections depended on a fracture mechanics analyses that were used to determine inspection criteria and intervals. The first fracture mechanics analysis was submitted and approved by the NRC in 1983.

The 1983 fracture mechanics analysis was replaced in 1998 by BWROG evaluations which provided improved UT techniques, flaw size acceptance criteria, and new inspection intervals (Reference 4.8.67). These BWROG evaluations relied on fracture mechanics analyses that modelled the flaws from a small crack which could not be detected, to large detectable cracks which were still significantly less than the size for which a failure may be expected. The fracture mechanics analysis assumed maximum growth rates. This evaluation (Reference 4.8.67) was accepted by the NRC in March 2000 as an acceptable alternative to the inspection guidelines in NUREG-0619. A plant-specific fracture mechanics analysis was performed for Units 2 and 3 in accordance with the BWROG and NRC approved guidance. This PBAPS plant-specific fracture mechanics analysis is not a TLAA because it does not involve time-limited assumptions defined by the current operating term, but rather provides the basis for inspection criteria and inspection intervals.

The implementation of the modifications and improvements to plant operations at low flow conditions in the early 1980's was effective in preventing additional rapid thermal cycle fatigue cracking in the PBAPS Units 2 and 3 feedwater nozzles (References 4.8.59 and 4.8.67).

The first PBAPS LRA credited "Augmented Inspections" in accordance with the Inservice Inspection (ISI) Program for the management of rapid thermal cycling fatigue cracking in feedwater nozzles. The inspections would, in effect, provide confirmation that cracking due to rapid thermal cycling fatigue or low cycle fatigue is not occurring. In addition, the first PBAPS LRA credited the Fatigue Management Activities Program for aging management of low cycle fatigue in the feedwater nozzles. This approach was evaluated by the NRC in NUREG-1769 and was found acceptable.

However, UFSAR Appendix C, Section C.5.3.1.1 documents that the feedwater nozzles have been evaluated for low cycle fatigue in accordance with ASME Section III as Class 1 components through the first period of extended operation. While the PBAPS plant-specific fracture mechanics analysis for rapid cycle thermal fatigue is not a TLAA, the original ASME Section III fatigue analysis of the feedwater nozzles is considered a TLAA and must be evaluated for the second period of extended operation.

TLAA Evaluation:

Periodic examinations of the feedwater nozzles, performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, provide confirmation that cracking due to rapid thermal cycling fatigue and low cycle fatigue is not occurring. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program is credited for managing rapid thermal cycling fatigue through the second period of extended operation.

Section 4.3.2 describes how the Fatigue Monitoring (B.3.1.1) program is credited with managing ASME Section III, Class 1 fatigue TLAAs. This includes fatigue associated with the feedwater nozzles. The Fatigue Monitoring program currently uses SI:FatiguePro™ to monitor low cycle fatigue of feedwater nozzles, computing the CUF_{en}-to-date values based upon the cumulative numbers of fatigue transients that have occurred as of the monitoring date. The feedwater nozzles have also been evaluated for environmental fatigue.

The SI:FatiguePro™ locations "Feedwater Nozzles (LAS)/Beyond Second Piston Ring" and "Feedwater Nozzles (CS)/Safe End Between First and Second Piston" will monitor fatigue for the feedwater nozzles to ensure that EAF usage factors will remain less than 1.0 through the second period of extended operation. These are shown on Table 4.3.1-3 as locations 3 and 4.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will continue to provide confirmation that cracking due to rapid thermal cycling fatigue has been mitigated. In addition, the Fatigue Monitoring (B.3.1.1) program will manage feedwater nozzle low cycle fatigue TLAAs through the second period of extended operation.

4.7.4 FRACTURE MECHANICS ANALYSIS OF ISI-REPORTABLE INDICATIONS FOR GROUP I PIPING: AS-FORGED LAMINAR TEAR IN A UNIT 3 MAIN STEAM ELBOW NEAR WELD 1-B-3BC-LDO DISCOVERED DURING PRESERVICE UT

TLAA Description:

A preservice ultrasonic volumetric examination (UT) discovered an imbedded as-forged laminar indication in an elbow on a PBAPS Unit 3 main steam line. The indication did not extend into a weld.

Although this portion of the main steam system piping is not subject to an ASME III Class 1 fatigue analysis, a stress evaluation and a 40-year-life fatigue analysis was performed. The analysis concluded that the primary, secondary, and primary plus secondary stresses and cumulative usage factors met ASME III requirements. As such, the evaluation was determined to be a TLAA in the first License Renewal Application and must be re-evaluated for the second period of extended operation.

TLAA Evaluation:

The original analysis calculated a 40-year worst case cumulative usage factor (CUF) of 0.036; assuming the laminar indication extends into the weld. A CUF of value 1.0 is considered the approximate threshold at which a fatigue crack may initiate and propagate. The first PBAPS LRA included projection to a maximum CUF of 0.054 for 60 years. In the SER for PBAPS's first LRA (Reference 4.8.66) the Staff concluded that: "By reporting that the CUF is considerably below the design limit of 1.0, the Staff concludes that the applicant has provided reasonable assurance that the flaw will not propagate during the 40-year life of the plant and the period of extended operation."

Projection of the 60-year maximum CUF value of 0.054 to 80 years on a proportional bases results in a maximum CUF of 0.072 for the 80-year period, which is less than the ASME Section III cumulative fatigue acceptance criterion of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) - The fatigue analysis of the as-forged laminar indication in the Unit 3 main steam elbow has been satisfactorily projected through the second period of extended operation.

4.7.5 UNIT 3 CORE SPRAY REPLACEMENT PIPING FATIGUE AND LEAKAGE ASSESSMENT

TLAA Description:

In 2013, portions of the Core Spray System piping segment located in the reactor vessel, from the thermal sleeves in reactor pressure vessel nozzles N5A and N5B to the shroud wall were replaced on Unit 3.

Some of the mechanical replacement hardware introduced a number of very small openings in the new piping segment and its attachment to the shroud wall, thus providing leakage paths. Therefore, a leakage assessment was performed to demonstrate that the new piping would perform its intended function through the remaining life of the unit. The leakage assessment assumed corrosion rates over 40 years.

In addition, a fatigue analysis of the new piping system and associated bolting concluded a maximum design CUF value of 0.0565.

Since the leakage assessment and fatigue analysis assumed a 40-year service life, until 2053, they have been identified as TLAAs that require evaluation for the second period of extended operation, which ends in 2054 for PBAPS Unit 3.

TLAA Evaluation:

Leakage Assessment

The leakage assessment was reevaluated by GEH for an additional five years, for a total of 45 years, until 2058. The assessment concluded that an additional five years of corrosion to the austenitic stainless steel and alloy 718 materials that makeup the leakage paths results in no changes to the calculated leakage.

The reevaluation concluded that the original leakage assessment remains valid for an additional five years for a total of 45 years, until 2058.

Fatigue Evaluation

The fatigue analysis, which concluded with a design CUF value of 0.0565, assumed the following transients, starting in 2013:

1) 161 cycles of Startup and Shutdown;
2) 197 cycles of Scram: Turbine Trip and All Other Scrams;
3) 80 cycles of Loss of Feedwater;
4) 40 cycles of Scram – Single Relief or Safety Valve Blowdown;
5) 50 Cycles of Injections; and
6) One OBE with 50 cycles.

The associated fatigue analysis was reevaluated by GEH for an additional five years of service life for a total of 45 years, until 2058. The reevaluation concluded that the originally assumed number of transient cycles, shown above; remain valid for 45 years and the design CUF value of 0.0565 remains unchanged.

Therefore, both the leakage assessment and the fatigue analysis are valid through the second period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) - The Unit 3 replacement core spray piping leakage assessment and the fatigue analysis remain valid through the second period of extended operation.

4.8 REFERENCES

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4.8.2 *NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP)*

4.8.3 *NUREG-2191, Revision 0, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report*

4.8.4 *NEI 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule*

4.8.5 *10 CFR 50.12, Specific Exemptions.*

4.8.6 *10 CFR 50.60, Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation*

4.8.7 *10 CFR 50, Appendix G, Fracture Toughness Requirements*

4.8.8 *10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements*

4.8.9 *NEDC-32983P-A, Rev. 2, Licensing Topical Report, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations, January 2006*

4.8.10 *NEDC-33006P-A, Class III, Revision 3, Licensing Topical Report, General Electric Boiling Water Reactor, Maximum Extended Load Line Limit Analysis Plus, June 2009, Proprietary*

4.8.11 *USNRC Safety Evaluation by the Office of Nuclear Reactor Regulation, GE Nuclear Energy Topical Report NEDC-32983P, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations, Project No. 710. Attached to NRC Letter MFN 01-050, Stuart A. Richards, Director, Project Directorate IV, to James F. Klapproth, Manager, Engineering and Technology, GE Nuclear Energy, Safety Evaluation for NEDC-32983P, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation, (TAC No. MA9891), September 14, 2001*

4.8.12 *USNRC letter, H. N. Berkow to G. B. Stramback, Final Safety Evaluation Regarding Removal of Methodology Limitations for NEDC-32983P-A, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation" (TAC No. MC3788), November 17, 2005*

4.8.13 *USNRC Regulatory Guide 1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001*

4.8.14 *BWRVIP-114-A, BWR Vessel and Internals Project, RAMA Fluence Methodology Theory Manual, 1019049, Final Report, June 2009*

4.8.15 *Letter from William H. Bateman, USNRC, to Bill Eaton, BWRVIP Chairman; Safety Evaluation of Proprietary EPRI Reports, BWRVIP RAMA Fluence Methodology Manual (BWRVIP-114), RAMA Fluence Methodology Benchmark Manual (BWRVIP-115), RAMA Fluence Methodology – Susquehanna Unit 2 Surveillance Capsule Fluence Evaluation for Cycles 1-5 (BWRVIP-117), RAMA Fluence Methodology Procedures Manual (BWRVIP-121), and Hope Creek Flux Wire Dosimeter Activation*

4.8.16 *BWRVIP-145-A: BWR Vessel and Internal Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Material Samples Using RAMA Fluence Methodology, 101905053. June 2009, Proprietary*

4.8.17 *Letter from Matthew A. Mitchell (U. S. NRC) to Rick Libra (BWRVIP), Safety Evaluation of Proprietary EPRI Report BWR Vessel and Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Material Samples Using RAMA Fluence Methodology (BWRVIP-145), dated February 7, 2008 (ML 100260948). (Attached to Reference 4.8.18)*

4.8.18 *Safety Evaluation by the Office of Nuclear Reactor Regulation BWRVIP-145, BWR Vessel and Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Material Samples Using RAMA Fluence Methodology*

4.8.19 *UFSAR Section 3.3.5.4 Thermal Shock*

4.8.20 *UFSAR Section 3.6, Nuclear Design*

4.8.21 *UFSAR Table 3.3.1, Reactor Vessel Internals Design Data*

4.8.22 *BWRVIP-74-A, BWR Vessel and Internals Project – BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal, June 2003, Proprietary*

4.8.23 *USNRC Regulatory Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Revision 2, May 1988*

4.8.24 *BWRVIP-135, BWR Vessel and Internals Project, Integrated Surveillance Program (ISP) Data Source Book and Plant Evaluations, Revision 3*

4.8.25 *Peach Bottom Unit 2 and Unit 3 Tech Specs 5.6.7, Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)*

4.8.26 *10 CFR 50.90, Application for Amendment of License, Construction Permit, or Early Site Permit*

4.8.27 *Safety Evaluation by the Office of Nuclear Reactor Regulation Proposed Alternative Relief Requests 14R51 and 14R52, Exelon Generation Company, Peach Bottom Atomic Power Station Units 2 and 3, Docket Numbers 50-277 and 50-278, dated January 24, 2012.*

4.8.28 *BWRVIP-05, BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations (BWRVIP-05), September 1995, Proprietary*

4.8.29 *BWRVIP-05 SER (Final), USNRC letter from Gus C. Lainas to Carl Terry, Niagara Mohawk Power Company, BWRVIP Chairman, Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, (TAC No. M93925), July 28, 1998*

4.8.30 *USNRC Generic Letter 98-05, Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief From Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds, November 10, 1998*

4.8.31 *Supplement To Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC NO. MA3395), March 7, 2000*

4.8.32 *Ranganath, S., Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident, Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979, Paper GI/5*

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4.8.34 *Safety Evaluation for Referencing of BWR Vessel and Internals Project, BWR Core Plate Inspection and Evaluation Guideline (BWRVIP-25), Report for Compliance with the Technical Information Requirements of the License Renewal Rule, December 7, 2000. (Attached to reference 4.8.35)*

4.8.35 *BWRVIP-25, Revision 1, BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines, December 2015, Proprietary*

4.8.36 *BWRVIP-25, Revision 0, BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines, December 1998, Proprietary*

4.8.37 *BWRVIP-276: BWR Vessel and Internals Project; Evaluation to Justify Core Plate Bolt Elimination, Section 6: Stress Relaxation Evaluation; Figure 6-4, Predicted Relaxation of Irradiated Austenitic Steels versus Existing Stainless-Steel Relaxation Data, Proprietary*

4.8.38 *NUREG/CR-6260, Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components, March 1995*

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4.8.40 *NUREG/CR-6909, Draft Revision 1, Effect of LWR Coolant Environments on Fatigue Life of Reactor Materials.*

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4.8.46 *BWRVIP-26-A: BWR Vessel and Internals Project BWR Tope Guide Inspection and Flaw Evaluation Guidelines, Proprietary*

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4.8.49 *UFSAR Section C.5.2, Loading Conditions and Allowable Limits*

4.8.50 *ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1965 Edition.*

4.8.51 *NUREG-0169, Rev 1, BWR Feedwater Nozzle and Control Rid Drive Return Line Nozzle Cracking: Resolution of Generic Technical Activity A-10 (Technical Report).*

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4.8.53 *UFSAR Appendix A, Section A.1.1*

4.8.54 *UFSAR Sections 10.4.10 and 10.11*

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4.8.58 *License Renewal Application Peach Bottom Atomic Power Station Units 2 and 3, Submitted in July 2, 2001, Exelon Letter*

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4.8.65 *Exelon Letter to NRC, Response to Request for Additional Information Related to Time-Limited Aging Analyses, dated May 1, 2002. (Response to RAI 4.7.1)*

4.8.66 *SER 20000310, USNRC Letter, Stuart A. Richards, Director, Project Directorate IV and Decommissioning, USNRC, to W. Glenn Warren, Chairman, BWR Owner's Group," Final Safety Evaluation of BWR Owner's Group Alternate Boiling Water Reactor (BWR) Feedwater Inspection (TAC No. MA6787)," March 10, 2000 (Attached to Reference 4.8.67)*

4.8.67 *BWR Owners' Group "Alternate BWR Feedwater Nozzle Inspection Requirements", GE-NE-523-A71-0594-A, Revision 1. August 1999.*

4.8.68 *USAS (ANSI) B31.1, Power Piping Code, 1967 Edition*

4.8.69 *Exelon Letter dated October 29, 2010, Submittal of Analytical Evaluations of Reactor Pressure Vessel Closure Head Indications. This letter contained*

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4.8.70 *Exelon Letter dated September 28, 2012, License Amendment Request – Extended Power Uprate. This letter contained*

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4.8.72 UFSAR Section 5.2.3.1 General Description of the Primary Containment.

4.8.73 NRC Letter Dated November 15, 2017, Peach Bottom Atomic Station, Units 2 and 3 – Issuance of Amendments Re: Measurement Uncertainty Recapture Power Uprate (CAC Nos. MF9289 and MF9290; EPID L-2017-LLS-0001)

4.8.74 February 8, 2018 Letter, Final Request For Additional Information for the Safety Review of the River Bend Station License Renewal Application (CAC NO. MF9757) – SET 10 – (Includes RAI 4.2.1-1) (Section 4.2.1.3)

4.8.75 NUREG-1796, Safety Evaluation Report Related to the License Renewal of the Dresden Nuclear Power Stations, Units 2 and 3 and Quad Cities Nuclear Power Stations, Units 1 and 2.

4.8.76 *NUREG/CR-6909, Revision 1, Effect of LWR Coolant Environments on Fatigue Life of Reactor Materials Final.*

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APPENDIX A FINAL SAFETY ANALYSIS REPORT SUPPLEMENT
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A.1.0 Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a FSAR Supplement. This appendix, which includes the following sections, comprises the FSAR supplement:

- Section A.1.1 contains a listing of the aging management programs that correspond to NUREG-2191 Chapter XI programs, including the status of the programs at the time the Second License Renewal Application was submitted.
- Section A.1.2 contains a listing of the plant-specific aging management programs, including the status of the programs at the time the Second License Renewal Application was submitted.
- Section A.1.3 contains a listing of aging management programs that correspond to NUREG-2191 Chapter X programs associated with Time-Limited Aging Analyses, including the status of the programs at the time the Second License Renewal Application was submitted.
- Section A.1.4 contains a listing of the Time-Limited Aging Analyses summaries (TLAAs).
- Section A.1.5 contains a discussion of the Quality Assurance Program and Administrative Controls.
- Section A.2 contains a summarized description of the aging management programs.
- Section A.2.1 contains a summarized description of the NUREG-2191 Chapter XI programs for managing the effects of aging.
- Section A.2.2 contains a summarized description of the plant-specific programs for managing the effects of aging.
- Section A.3 contains a summarized description of the NUREG-2191 Chapter X programs that support the TLAAs.
- Section A.4 contains a summarized description of the TLAAs applicable to the second period of extended operation.
- Section A.5 contains the Second License Renewal Commitment List.

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the period of extended operation. The second period of extended operation is defined as 20 years from the unit's current operating license expiration date.

A.1.1 NUREG-2191 Chapter XI Aging Management Programs

The NUREG-2191 Chapter XI Aging Management Programs (AMPs) are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements.

The following list reflects the status of these programs at the time of the Second License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in the Appendix A.5 Second License Renewal Commitment List.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.1.1) [Existing]
2. Water Chemistry (Section A.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section A.2.1.3) [Existing]
4. BWR Vessel ID Attachment Welds (Section A.2.1.4) [Existing]
5. BWR Stress Corrosion Cracking (Section A.2.1.5) [Existing]
6. BWR Penetrations (Section A.2.1.6) [Existing]
7. BWR Vessel Internals (Section A.2.1.7) [Existing - Requires Enhancement]
8. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.2.1.8) [New]
9. Flow-Accelerated Corrosion (Section A.2.1.9) [Existing - Requires Enhancement]
10. Bolting Integrity (Section A.2.1.10) [Existing - Requires Enhancement]
11. Open-Cycle Cooling Water System (Section A.2.1.11) [Existing - Requires Enhancement]
12. Closed Treated Water Systems (Section A.2.1.12) [Existing - Requires Enhancement]
13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.1.13) [Existing - Requires Enhancement]
14. Compressed Air Monitoring (Section A.2.1.14) [Existing - Requires Enhancement]
15. BWR Reactor Water Cleanup System (Section A.2.1.15) [Existing]

16. Fire Protection (Section A.2.1.16) [Existing - Requires Enhancement]
17. Fire Water System (Section A.2.1.17) [Existing - Requires Enhancement]
18. Outdoor and Large Atmospheric Metallic Storage Tanks (Section A.2.1.18) [Existing - Requires Enhancement]
19. Fuel Oil Chemistry (Section A.2.1.19) [Existing - Requires Enhancement]
20. Reactor Vessel Material Surveillance (Section A.2.1.20) [Existing - Requires Enhancement]
21. One-Time Inspection (Section A.2.1.21) [New]
22. Selective Leaching (Section A.2.1.22) [New]
23. ASME Code Class 1 Small-Bore Piping (Section A.2.1.23) [New]
24. External Surfaces Monitoring of Mechanical Components (Section A.2.1.24) [New]
25. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.1.25) [New]
26. Lubricating Oil Analysis (Section A.2.1.26) [Existing]
27. Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section A.2.1.27) [Existing]
28. Buried and Underground Piping and Tanks (Section A.2.1.28) [Existing - Requires Enhancement]
29. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section A.2.1.29) [New]
30. ASME Section XI, Subsection IWE (Section A.2.1.30) [Existing - Requires Enhancement]
31. ASME Section XI, Subsection IWF (Section A.2.1.31) [Existing - Requires Enhancement]
32. 10 CFR Part 50, Appendix J (Section A.2.1.32) [Existing]
33. Masonry Walls (Section A.2.1.33) [Existing - Requires Enhancement]
34. Structures Monitoring (Section A.2.1.34) [Existing - Requires Enhancement]

35. Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.1.35) [Existing - Requires Enhancement]

36. Protective Coating Monitoring and Maintenance (Section A.2.1.36) [Existing - Requires Enhancement]

37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.37) [Existing - Requires Enhancement]

38. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.2.1.38) [Existing - Requires Enhancement]

39. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.39) [Existing - Requires Enhancement]

40. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.40) [New]

41. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.41) [New]

42. Metal Enclosed Bus (Section A.2.1.42) [New]

43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.43) [New]

A.1.2 Plant-Specific Aging Management Programs

The plant-specific aging management programs are described in the following sections. The following list reflects the status of these programs at the time of the Second License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in Appendix A.5 Second License Renewal Commitment List.

1. Wooden Pole (Section A.2.2.1) [Existing - Requires Enhancement]

A.1.3 NUREG-2191 Chapter X Aging Management Programs

The NUREG-2191 Chapter X Aging Management Programs (AMP) associated with Time-Limited Aging Analyses are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 Chapter X or require enhancements. The following list reflects the status of these programs at the time of the Second License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in Appendix A.5 Second License Renewal Commitment List.

1. Fatigue Monitoring (Section A.3.1.1) [Existing - Requires Enhancement]

2. Neutron Fluence Monitoring (Section A.3.1.2) [Existing - Requires Enhancement]

3. Environmental Qualification of Electric Equipment (Section A.3.1.3) [Existing - Requires Enhancement]

A.1.4 Time-Limited Aging Analyses

Summaries of the Time-Limited Aging Analyses applicable to the second period of extended operation are included in the following sections:

1. Reactor Vessel and Internals Neutron Embrittlement Analyses (Section A.4.2.1)

2. Reactor Vessel Neutron Fluence Analyses (Section A.4.2.1.1)

3. Reactor Vessel Internals Neutron Fluence Analyses (Section A.4.2.1.2)

4. Reactor Vessel Upper-Shelf Energy (USE) Analyses (Section A.4.2.2)

5. Reactor Vessel Adjusted Reference Temperature (ART) Analyses (Section A.4.2.3)

6. Reactor Vessel Pressure – Temperature Limits (Section A.4.2.4)

7. Reactor Vessel Circumferential Weld Failure Probability Analyses (Section A.4.2.5)

8. Reactor Vessel Axial Weld Failure Probability Analyses (Section A.4.2.6)

9. Reactor Vessel Reflood Thermal Shock Analysis (Section A.4.2.7)

10. Core Shroud Reflood Thermal Shock Analysis (Section A.4.2.8)

11. Core Plate Rim Hold-Down Bolt Loss of Preload Analysis (Section A.4.2.9)

12. Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis (Section A.4.2.10)

13. Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis (Section A.4.2.11)

14. Jet Pump Riser Repair Clamp Loss of Preload Analysis (Section A.4.2.12)

15. Replacement Core Plate Extended Life Plug Irradiation-Enhanced Stress Relaxation Analysis (Section A.4.2.13)

16. First License Renewal Application Core Shroud IASCC and Embrittlement Analysis (Section A.4.2.14)

17. Unit 3 Core Spray Replacement Piping Bolting Loss of Preload Evaluation (Section A.4.2.15)

18. Transient Cycle and Cumulative Fatigue Usage Projections for 80 Years (Section A.4.3.1)

19. ASME Section III, Class 1 Fatigue Analyses (Section A.4.3.2)

20. ASME Section III, Class 1 Fatigue Waivers (Section A.4.3.3)

21. ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses (Section A.4.3.4)

22. Environmental Fatigue Analyses for RPV and Class 1 Piping (Section A.4.3.5)

23. Reactor Vessel Internals Fatigue Analyses (Section A.4.3.6)

24. Generic BWR Fatigue Analyses for Various Reactor Vessel Internal Components (Section A.4.3.6.1)

25. Generic BWR Fatigue Analyses for the Core Shroud (Section A.4.3.6.2)

26. Core Shroud Support Fatigue Analyses Reevaluation (Section A.4.3.6.3)

27. Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis (Section A.4.3.6.4)

28. Replacement Steam Dryer Stress Report and Fatigue Evaluation (Section A.4.3.6.5)

29. High-Energy Line Break (HELB) Analyses Based Upon Cumulative Fatigue Usage (Section A.4.3.7)

30. Inservice 60-Year RPV Closure Head Weld Flaw Analyses (A.4.3.8)

31. Environmental Qualification of Electric Equipment (Section A.4.4.1)

32. Concrete Containment Tendon Prestress Analyses (Section A.4.5.1)

33. Primary Containment Structures, Penetrations, and Associated Components with Fatigue Analyses (Section A.4.6.1)

35. Containment Process Line Penetration Bellows (Section A.4.6.2)

36. Cranes Cyclic Loading Analyses (Section A.4.7.1)

37. Reactor Vessel Main Steam Nozzle Clad Removal Corrosion Allowance (Section A.4.7.2)

38. Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking” (Section A.4.7.3)

39. Fracture Analysis of ISI-Reportable Indications for Group I Piping: As-forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT (Section A.4.7.4)

40. Unit 3 Core Spray Replacement Piping Fatigue and Leakage Assessment (Section A.4.7.5)

A.1.5 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, “Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR). In many cases, existing activities were found adequate for managing aging effects during the second period of extended operation.

A.1.6 Operating Experience

Operating experience from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience program, which meets the requirements of NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.” The operating experience program interfaces with and relies on active participation in the INPO operating experience program, as endorsed by the NRC. In accordance with these programs, all incoming operating experience items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development is also reviewed. Items so identified are further evaluated and the AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and to those who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience program.

A.2.0 Aging Management Programs

A.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 programs credited for managing the effects of aging.

A.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition monitoring program that consists of periodic volumetric, surface, and visual examinations of ASME Class 1, 2, and 3 components including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions. The examinations are implemented in accordance with 10 CFR 50.55a and ASME Code, Section XI Subsections IWB, IWC, and IWD. The program includes augmented inservice inspection requirements for periodic examination of the reactor vessel feedwater nozzles in accordance with the staff-approved recommendations provided within BWR Owners Group (BWROG) Licensing Topical Report, “Alternate BWR Feedwater Nozzle Inspection Requirements,” GE-NE-523-A71-0594-A, Revision 1, May 2000. These activities include examinations, evaluations, monitoring, and trending of results to confirm that effects of cracking, loss of material, loss of fracture toughness, and loss of preload for pressure-retaining bolting are managed effectively during the second period of extended operation.

A.2.1.2 Water Chemistry

The Water Chemistry program is an existing program that mitigates aging effects of loss of material due to corrosion, cracking due to SCC, and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environment. Chemistry programs are used to control water chemistry for parameters such as conductivity, chloride, and sulfate that accelerate corrosion. The Water Chemistry program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the system-specific limits, based on the industry recognized guidelines of the Boiling Water Reactor Vessel and Internals Project (BWRVIP-190, Revision 1, Electric Power Research Institute - 3002002623). In addition, the Water Chemistry program is credited for mitigating loss of material and cracking for components exposed to sodium pentaborate and auxiliary steam environments.

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that manages reactor head closure studs, flange threads, and associated nuts, washers, and bushings, for cracking and loss of material. The program is implemented through station procedures based on the examination requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and preventive measures to mitigate cracking as delineated in NRC Regulatory Guide 1.65, Revision 1, with the exception that existing stud bolting components have a measured yield strength greater than or equal to 150 ksi and an ultimate tensile stress greater than or equal to 170 ksi. Also, potential replacement stud bolting components in the warehouse have measured yield strength greater than or equal to 150 ksi.

A.2.1.4 BWR Vessel ID Attachment Welds

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of the reactor vessel interior attachment welds. 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, and BWRVIP-48-A. 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-A. 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-A and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A.

A.2.1.5 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel based alloy that are 4 inches or larger in diameter containing reactor coolant at a temperature above 200 degrees F during power operation, regardless of code classification, with the exception of reactor water cleanup system piping that is outboard of the second (outboard) primary containment isolation valve, that is managed by the BWR Reactor Water Cleanup System (A.2.1.15) aging management program.

The program includes periodic volumetric examinations to detect and manage IGSCC in accordance with NRC GL 88-01. The extent and schedule of inspection described in GL 88-01 are modified in accordance with the inspection guidance in staff-approved BWRVIP-75-A. Welds classified as IGSCC Category A may be subsumed into the Risk-Informed Inservice Inspection program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A, pending approval of ASME Code relief requests during the second period of extended operation. The program includes the staff-approved positions delineated in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1 regarding selection of IGSCC resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

A.2.1.6 BWR Penetrations

The BWR Penetrations aging management program is an existing condition monitoring program that manages the effects of cracking due to cyclic loading or stress corrosion cracking of BWR instrumentation penetrations, CRD housing and incore-monitoring housing penetrations, and the SLC/Core Plate dP nozzle exposed to reactor coolant by performing inspections and flaw evaluations. In addition to the requirements of ASME Code, Section XI, Subsection IWB, the BWR Penetrations program incorporates the inspection and flaw evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," BWRVIP-27-A, “BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines,” and the water chemistry recommendations described in the Water Chemistry (A.2.1.2) program. The examination categories include volumetric, surface, and visual examination methods.

A.2.1.7 BWR Vessel Internals

The BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents, and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including martensitic stainless steel (not installed in PBAPS reactor vessel internals), cast stainless steel and associated welds).

The program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload for core plate rim hold-down bolts and jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity. Enhanced guidance will be used for inspections of the Westinghouse (Nordic style) steam dryers.

Evaluations of reactor vessel internal component determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement and cracking due to IASCC during the second period of extended operation. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components.

The BWR Vessel Internals aging management program will be enhanced to:

1. Install core plate wedges no later than six months prior to the second period of extended operation, or before the end of the last refueling outage prior to the second period of extended operation, whichever occurs later; or, submit an inspection plan for the core plate rim hold-down bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation.

2. Perform a VT-3 inspection of the jet pump inlet mixer and beam regions every refuel cycle after a fluence value of 1.3E+20 n/cm^2 (51 EFPY for Unit 2 and 63 EFPY for Unit 3) is reached at the jet pump holddown beam.

3. Perform periodic visual inspections of the PBAPS Westinghouse (Nordic style) stainless steel steam dryers for the aging effects of loss of material and cracking at a frequency not exceeding 10 years, with the first inspections performed prior to the second period of extended operation, as described below.

The inspection guidance contained in BWRVIP-139-A does not address the Westinghouse (Nordic style) steam dryers installed in PBAPS Unit 2 and Unit 3 and therefore is not directly applicable. However, the general principles and conclusions from BWRVIP-139-A, "BWR Vessel and Internals Project: Steam Dryer Inspection and Flaw Evaluation Guidelines", BWRVIP-181-R1-A, "BWR Vessel and Internals Project: Steam Dryer Repair Design Criteria", and Regulatory Guide 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing" were applied to the inspection plan described in WCAP-17635-P, "Peach Bottom Atomic Power Station Unit 2 and Unit 3 Replacement Steam Dryer Comprehensive Vibration Assessment Program (CVAP)". WCAP-17635-P also includes manufacturer's recommendations based on relevant operating experience. The scope of the inspection will include the items listed in Table 1 below.

The steam dryer inspections are based on the BWRVIP-139-A and WCAP-17635-P guidelines to identify loss of material (wear) and cracking using appropriate visual examination techniques (e.g., VT-1, VT-3) and qualified inspectors. The examination procedures identify the type and location of examination required for each dryer component as well as the reason for inspection. Acceptance criteria are consistent with BWRVIP-139-A and are described in procedures and work instructions. Flaws and abnormal indications identified will be entered into the corrective action program for engineering evaluation. The evaluations will consider increasing inspection frequency and scope as appropriate. Identified degradation left in the as found condition will be reinspected as required by the engineering evaluation.

The repair design criteria contained in BWRVIP-181-R1-A and BWRVIP-139-A will be used for any future repairs of the steam dryers. Repairs to the steam dryer will be inspected as specified in the repair design package.

Table 1

Steam Dryer Inspection Program for the Second Period of Extended Operation in accordance with WCAP-17635-P

Inspection Location	Basis for Selection
1. Overall General Inspection of Outside of the Replacement Steam Dryer (to include outside of skirt)	Industry Operating Experience (BWRVIP-139-A, Section 1.1, Section 2.4.2) General Inspection for evidence of damage
2. Lifting Rods Top Ends (Unit 3 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
3. Hold Down Rods Top Ends (Unit 2 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
4. Support Ring Bottom Surface	RG 1.20 Sec 2.3 (1)(b,d) Surfaces in contact during operation
5. Outer hood (welds on outer surface)	Industry Operating Experience (BWRVIP-139-A, Section 1.1, Section 2.4.2) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)
6. Outer Ring Top Cage	Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)
7. Weld attachments between the brackets to the lifting rod and hold down rod and weld attachments between the brackets to top plate (lifting rod, Unit 3 only)	Industry Operating Experience (BWRVIP-139-A, Section 2.4.8) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)

These enhancements will be implemented in accordance with the schedule described within each enhancement. Initial steam dryer inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide assurance that reactor coolant pressure boundary CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement meet their intended functions. The ASME Code Class 1 CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The PBAPS ASME Section XI Inservice Inspection program is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program which will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250 degrees Celsius (482 degrees Fahrenheit). PBAPS Unit 2 and Unit 3 do not have any Class 1 piping or fittings fabricated from CASS. The Class 1 reactor recirculation pump casings and covers are fabricated from CASS.

The program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Components with the potential for significant thermal aging embrittlement will be managed through either, qualified visual inspections, such as enhanced visual examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation. For pump casings, as an alternative to screening for significance of thermal aging embrittlement, no further actions are needed if a flaw tolerance evaluation performed as part of Code Case N-481 implementation is bounding for 80 years.

Inspections or evaluations are not required for components for which thermal aging embrittlement is not significant. In addition, screening for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement is not required, because the existing ASME Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies.

Reactor vessel internal components fabricated from CASS are not within the scope of this aging management program and are managed by the BWR Vessel Internals (A.2.1.7) aging management program.

This new aging management program will be implemented no later than six months prior to the second period of extended operation.

A.2.1.9 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion (FAC). The program is based on commitments made in response to NRC Generic Letter 89-08, “Erosion/Corrosion Induced Pipe Wall Thinning,” and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R4 for an effective FAC program.

CHECWORKS is used to predict component wear rates and remaining service life in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS model is also refined by importing actual volumetric inspection data thickness measurements and re-running wear rate analyses. This improves the predictive capability of the model to ensure that intended functions are maintained.

The program also manages wall thinning caused by mechanisms other than FAC in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data against acceptance criteria to determine the need for corrective actions including inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The Flow-Accelerated Corrosion aging management program will be enhanced to:

1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for the second period of extended operation.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.10 Bolting Integrity

The Bolting Integrity aging management program is an existing condition monitoring program. The program manages aging for loss of preload, cracking, and loss of material of safety-related and nonsafety-related closure bolting on pressure-retaining components. The program utilizes recommendations and guidelines delineated in NUREG-1339, EPRI NP-5769, TR-1015336, and TR-1015337 for material selection, use of approved lubricants, proper torqueing, and leakage evaluations which are implemented during plant surveillance and maintenance activities.

In addition, the program manages aging of submerged mechanical bolting on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens.

The program includes periodic visual inspections of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material as evidenced by pressure-retaining joint leakage. Closure bolting on pressure-retaining components and mechanical bolting that are submerged or closure bolting on pressure-retaining components located in piping systems that contain air or gas is inspected by alternative means, such as by sample based periodic inspections. The program also includes preventive measures provided in the EPRI guidance documents to preclude or minimize loss of preload and cracking.

There is no high strength bolting material with actual yield strength of 150 ksi or greater on pressure-retaining components with bolt diameters greater than 2 inches, or bolts with unknown yield strength within the scope of this program. Therefore, sampling based volumetric examinations of closure bolting to detect indications of cracking is not applicable.

The program performs periodic sample based inspections on submerged closure bolting on the ESW, HPSW, and fire protection pumps; submerged closure bolting on the Core Spray, HPCI, RHR, and RCIC suction strainers; and submerged mechanical bolts on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens. The program also performs periodic inspections on submerged closure bolting on the emergency cooling water pump.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program includes inspection of safety-related closure bolting on pressure-retaining components, and supplements this program. Inspection activities for bolting in a buried environment or underground with restricted access are performed in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks (A.2.1.28) program.

The Reactor Head Closure Stud Bolting (A.2.1.3) program manages the aging effects of the bolting components for the reactor vessel closure head. The ASME Section XI, Subsection IWE (A.2.1.30) program, ASME Section XI, Subsection IWF (A.2.1.31) program; Structures Monitoring (A.2.1.34) program; RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (A.2.1.35) program; Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (A.2.1.13) program; manage the aging effects of safety-related and nonsafety-related structural bolting. The External Surfaces Monitoring of Mechanical Components (A.2.1.24) program manages the aging effects of safety-related and nonsafety-related bolting associated with ductwork for heating, ventilation, and air conditioning systems.

The Bolting Integrity aging management program will be enhanced to:

1. Ensure that submerged carbon steel closure bolts on the ESW, HPSW, and fire protection pumps are inspected for loss of material and to confirm that the closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of closure bolting on these pumps during pump overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation.

2. Ensure that submerged stainless steel mechanical bolts on the 2AS008,

2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens are inspected for loss of material and to confirm that the mechanical bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of mechanical bolting on these screens during overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation.

3. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for cracking and loss of material for the carbon steel/ air-indoor uncontrolled and the stainless steel/ air-indoor uncontrolled material and environment combinations. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Opportunistic inspections during maintenance activities may be credited during the same 10-year period.

4. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for loss of material for the carbon steel/ air-outdoor material and environment combination. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 25 bolt inspections shall be performed each 10-year period during the second period of extended operation for both Units 2 and 3. Opportunistic inspections during maintenance activities may be credited during the same 10-year period.

5. Revise site walkdown procedures to specify proper lighting and appropriate distances to adequately identify visible component leakage, evidence of past leakage, or other age-related degradation on pressure–retaining bolted joints that contain fluids such as water, oil, or steam. Cameras and video equipment may be used to supplement these inspections.

6. Revise existing repetitive tasks to provide guidance for proper lighting and appropriate inspection distances to adequately identify loss of material in submerged environments. Cameras and video equipment may be used to supplement these inspections.

7. Ensure no fewer than five additional bolts are inspected for each sample based inspection that does not meet acceptance criteria, or 20 percent of the total bolt population of each applicable material, environment, and aging effect combination; whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis are performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval for which the original sample based inspections are conducted.

These enhancements will be implemented no later than six months prior to the second period of extended operation.

A.2.1.11 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program based on the implementation of NRC GL 89-13, and includes nonsafety-related portions of the open cycle cooling water system. The program includes: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, (c) periodic inspection and maintenance so that corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open cycle cooling water system. This program includes guidance beyond the requirements contained in NRC GL 89-13, such as inputs from industry reports and documents (e.g., EPRI documents) that address operating experience such that aging effects are adequately managed.

The Open-Cycle Cooling Water System aging management program will be enhanced to:

1. Provide procedural direction to perform additional inspections if the cause of the aging effect for each applicable material and environment combination is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. These additional inspections will be conducted if any of the inspections do not meet acceptance criteria. No fewer than five additional inspections will be performed for each inspection that does not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.12 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigative program that manages loss of material, cracking, and reduction of heat transfer in piping, piping components, tanks, and heat exchangers exposed to a closed cycle cooling water environment. The program will be enhanced to include condition monitoring activities. The program includes: (a) nitrite-based water treatment, including pH control and the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion, stress corrosion cracking, or fouling.

The program uses EPRI guidelines for chemistry control of closed cooling water systems. Corrosion coupon testing is not used; corrosion monitoring is performed by monitoring for total iron and total copper which indicates if active corrosion is occurring. Testing and treating for microbiological growth is performed.

Periodic inspections of a representative sample will be performed, at a minimum, in each 10-year period during the second period of extended operation. The inspections will include opportunistic visual inspections and periodic inspections to satisfy the sample size requirements using techniques capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects. Opportunistic visual inspections will be performed whenever a system boundary is opened.

The inspections will focus on the components most susceptible to aging because of time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water. A representative sample is 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 19 components per population at each unit. At least 20 percent of the surface area will be 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 19 inspections per unit. Additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections will be determined in accordance with the corrective action program; however, no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional components will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections at both Unit 2 and 3 with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval in which the original inspection was conducted.

Due to the water chemistry controls, no age-related degradation is expected; therefore, any detectable loss of material, cracking, or fouling will be evaluated in the corrective action program. Identified age-related degradation will be projected until the next scheduled inspection and results evaluated to confirm that the sampling bases will maintain the component’s intended functions throughout the second period of extended operation. If fouling is identified, the overall effect will be evaluated for reduction of heat transfer, flow blockage, and loss of material.

Inspections will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspections will follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring including opportunistic visual inspections and sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the second period of extended operation. The rate of identified degradation will be projected until the next scheduled inspection. Additional sample-based inspections will be performed if aging effects are identified. If those inspections identify aging effects, the corrective action program will be used to determine the extent of condition and extent of cause to determine the further extent of inspections.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing condition monitoring program that manages the effects of loss of material due to corrosion and wear, cracking, deformation, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.” The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging effects. Monitoring and maintenance of structural components of crane handling systems follow the maintenance rule requirements provided in 10 CFR 50.65.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be enhanced to:

1. Provide additional guidance to include inspection of crane-related bridges, structural members, and structural components for deformation, cracking, and loss of material due to corrosion or wear; and associated bolted connections for loss of material, cracking, and indications of loss of preload.

2. Provide procedural direction to document deficiencies identified during inspection activities within the corrective action program.

3. Provide site-specific procedural direction to evaluate and repair visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series.

These enhancements will be implemented no later than six months prior to the second period of extended operation.

A.2.1.14 Compressed Air Monitoring

The Compressed Air Monitoring aging management program is an existing condition monitoring program that consists of monitoring moisture content and corrosion, and performance of the compressed air system, including: (a) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits, and (b) inspection of components for indications of loss of material due to corrosion.

This program is based on the PBAPS response to NRC GL 88-14 and INPO's SOER 88-01. It also relies on the guidance from the ASME operations and maintenance standards and guides (ASME OM-S/G-2012, Division 2, Part 28) and ANSI/ISA-7.0.1-1996, and EPRI TR–10847 for testing and monitoring air quality and moisture. Additionally, periodic opportunistic visual inspections of component internal surfaces will be performed for signs of loss of material due to corrosion. Program activities include air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits, and inspections of the internal surfaces of compressed air system components for signs of loss of material due to corrosion.

The Compressed Air Monitoring aging management program will be enhanced to:

1. Perform daily inspection of instrument nitrogen after dryer desiccant for signs of moisture. Results will be recorded and reviewed to determine if corrective actions are required.

2. Perform opportunistic visual inspections of component internal surfaces exposed to a dry air environment for signs of loss of material due to corrosion.

These enhancements will be implemented no later than six months prior to the second period of extended operation.

A.2.1.15 BWR Reactor Water Cleanup System

The BWR Reactor Water Cleanup System program is an existing condition monitoring and mitigation program that includes the requirements to perform augmented inservice inspection (ISI) to manage stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) for stainless steel Reactor Water Cleanup (RWCU) system piping welds outboard of the second (outboard) primary containment isolation valves. Piping that contains reactor coolant at a temperature above 200 degrees Fahrenheit during power operation, and has a nominal diameter of 4 inches or larger, regardless of ASME Code classification is included within the scope of the program. The program includes the measures delineated in NUREG-0313, Revision 2, NRC Generic Letter (GL) 88-01 and its Supplement 1. For PBAPS Units 2 and 3, the NRC previously approved a reduced extent and schedule for inspection of IGSCC susceptible welds within the RWCU system that are outboard of the second isolation valves. The approved alternate extent and schedule is to perform ISI on two percent of the IGSCC susceptible welds during each refueling outage. The program is implemented in conjunction with the Water Chemistry (A.2.1.2) program to minimize the potential of cracking due to SCC or IGSCC in a treated water environment.

A.2.1.16 Fire Protection

The Fire Protection aging management program is an existing condition monitoring and performance monitoring program that includes fire barrier visual inspections and low pressure carbon dioxide system visual inspections and functional testing. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire dampers, and other materials that perform a fire barrier function. Periodic visual inspection and functional testing of the fire rated doors is performed to ensure that their functionality is maintained and aging effects managed. The program also includes visual inspections and periodic functional tests of the low pressure carbon dioxide fire suppression systems using the National Fire Protection Association Codes and Standards for guidance.

The Fire Protection aging management program will be enhanced to:

1. Perform periodic visual inspection every 18 months for identification of corrosion that may lead to loss of material on the external surfaces of the low pressure carbon dioxide fire suppression systems.

2. Perform periodic visual inspection of combustible liquid spill retaining curbs every 24 months.

These enhancements will be implemented no later than six months prior to the second period of extended operation.

A.2.1.17 Fire Water System

The Fire Water System aging management program is an existing condition monitoring program that manages aging effects such as loss of material and flow blockage due to fouling associated with water-based fire protection system components. The program manages these aging effects through the use of system pressure monitoring, system header flushing, underground main supply flow testing, pump performance testing, hydrant flushing, sprinkler system and deluge system flow testing, visual inspections, and volumetric examinations performed using the guidance of NFPA 25, 2011 Edition.

The program does not manage cracking as an aging effect because the PBAPS Fire Water System does not contain fire water storage tanks or high density polyethylene (HDPE) pipe. The fire main underground cement lined pipe aging effects including cracking are managed by the Internal Coating/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (A.2.1.29) program.

Testing or replacement of sprinklers that have been in place for 50 years is performed using the guidance of NFPA 25, 2011 Edition.

PBAPS does not have water-based fire protection systems that are normally dry but periodically subject to flow and cannot be drained. Therefore, augmented testing in addition to that specified in NFPA 25 is not required.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

Visual inspections and volumetric wall thickness examinations are used to detect corrosion and loss of material. The visual inspection techniques are capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. When visual inspections detect such irregularities, follow-up volumetric wall thickness examinations are performed. When the presence of foreign material that could cause flow blockage is found, the material will be removed and the source corrected by the use of the corrective action program. Inspections and tests follow site procedures that include specific inspection guidance and parameters such as lighting, distance, offset, protective coatings, and cleaning processes for an adequate examination.

The Fire Water System aging management program will be enhanced to:

1. Revise flow test procedures to include:

    a. Inspector test flush acceptance criteria for wet pipe sprinkler systems that currently do not include the requirement to record time to flow from the opened test valve.

    b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10 percent reduction in full flow pressure when compared to previously performed tests. An issue report shall be generated in the corrective action program to determine the cause and corrective actions.

    c. If acceptance criteria are not met, at least two additional tests shall be performed. If acceptance criteria are not met during follow-up testing, the test shall be performed on the same system, on the other unit.

2. Perform air flow tests on the hydrogen seal oil and reactor building water curtains every two years to ensure deluge piping and nozzles are unobstructed and there are no flow blockages.

3. Increase the frequency of air flow tests through the standby gas treatment and recombiner system deluge piping and nozzles to every two years to ensure piping and nozzles are unobstructed and there are no flow blockages.

4. Revise procedures to improve guidance for external visual inspections of the in scope sprinkler systems piping and sprinklers at least every two years to inspect for excessive corrosion, loss of material, leaks, and proper sprinkler orientation. Corroded, leaking or damaged sprinklers shall be replaced.

5. Perform external visual inspections of the in scope above ground fire main piping every two years to identify excessive corrosion, loss of material, leaks, and physical damage.

6. Perform internal visual inspections of sprinkler and deluge system piping to

identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric wall thickness examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the corrective action program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25 Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:

a. Wet pipe sprinkler systems - 50 percent of the wet pipe sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

c. Deluge systems - Yard transformer deluge systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

7. Perform a one-time volumetric wall thickness inspection, prior to the second period of extended operation, on a sample of the original yard transformer deluge system supply piping that was not replaced during transformer replacements and is periodically subjected to flow during functional testing.

8. Revise service water bay inspection procedures to include inspection of the motor driven fire pump intake strainer.

9. Perform flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five-year frequency to demonstrate the capability to provide the design pressure at required flow.

10. Flush deluge system mainline supply basket strainers until clear, following functional testing of yard deluge systems.

11. Perform a one-time inspection of the auxiliary boiler fuel oil storage tank internal foam nozzle and deflector, prior to the second period of extended operation, to ensure proper configuration and orientation and no indication of flow blockage.

12. Perform an internal inspection of the auxiliary boiler oil storage tank foam system foam concentrate tank every 10 years to ensure it is free of corrosion, debris, or foreign material that could cause flow blockage, and to ensure there

are no cracks or leaks and it is in good condition.

13. Revise restoration procedures for the hydrogen seal oil and reactor building water curtain systems to utilize low point drains following control valve actuations to ensure there is no trapped water in the system.

14. Revise restoration procedures for the yard transformer deluge systems to utilize low point drains after functional testing.

These enhancements will be implemented no later than six months prior to the second period of extended operation. Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.18 Outdoor and Large Atmospheric Metallic Storage Tanks

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program is an existing condition monitoring program that manages aging effects associated with in-scope outdoor aboveground tanks constructed on concrete or soil. PBAPS has no indoor, large volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, and no indoor tanks that sit on, or are embedded in concrete, where specific operating experience indicates that the tank surfaces are periodically exposed to moisture. The scope of this program includes the Unit 2 condensate storage tank, the Unit 3 condensate storage tank, and the common refueling water storage tank. These tanks contain treated water, are constructed of carbon steel, are not insulated, are coated both internally and externally as a preventive measure to mitigate corrosion, and are supported on a concrete or asphalt and sand foundation, such that the bottoms of the tanks are inaccessible for direct visual inspection. Sealant is used at the concrete or asphalt interface with the tank.

The program manages loss of material by conducting periodic internal and external visual inspections on a frequency of 10 years or less. Cracking is not a predicted aging effect due to the carbon steel construction. Visual inspections of sealant and caulking will be supplemented with physical manipulation to detect degradation. Thickness measurements of tank bottoms are conducted to ensure that significant degradation is not occurring. Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions, as defined for visual and ultrasonic inspection techniques.

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program will be enhanced to:

1. Perform a visual inspection of the sealant at the perimeter of the condensate storage tanks and refueling water storage tank bases for signs of degradation every two years. The visual inspections of sealant and caulking are supplemented with physical manipulation to detect degradation.

2. Perform a pre-inspection review of the previous two inspections of the

internal tank coatings, when available, that includes review of results of inspections and any subsequent repair activities.

3. Conduct training and qualification of individuals involved in internal coating or lining inspections and evaluating degraded conditions in accordance with an ASTM International standard endorsed in RG 1.54.

4. Perform volumetric inspection of Unit 2 and 3 condensate storage tanks and refueling water storage tank bottoms at least once during the 10-year period prior to the second period of extended operation, and at least once every 10 years during the second period of extended operation. Volumetric inspections are performed at representative sample locations to include 25 one square foot locations or 20 percent coverage conducted in different locations unless the program states the basis for why repeated inspections are conducted in the same location (i.e. previous findings). Additionally, a minimum of 10 of the random one square foot sample locations will be performed within the 30-inch band at the perimeter of the shell. The scope of subsequent examinations may be adjusted based upon the results of previous examinations.

These enhancements will be implemented no later than six months prior to the second period of extended operation, unless a more specific schedule is described within the enhancement (i.e., Enhancement 4). Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.19 Fuel Oil Chemistry

The Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The program relies on a combination of surveillance and maintenance procedures. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic cleaning and draining of tanks and by verifying the quality of fuel oil. Fuel oil sampling and analysis is performed in accordance with approved procedures for stored fuel oil and new fuel oil before its introduction into the storage tanks.

The Fuel Oil Chemistry aging management program will be enhanced to:

1. Perform periodic internal inspection of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543) at least once during the 10-year period prior to the second period of extended operation, and at least once every 10 years during the second period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed

during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected.

2. Perform periodic (quarterly) removal of water collected at the bottom of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543).

3. Perform receipt testing of new fuel oil for particulate concentration and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040), diesel generator fuel oil storage tanks (0A(B,C,D)T038), and diesel fire pump fuel oil storage tank (00T041).

4. Perform periodic (quarterly) sampling and analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040). Sampling activities will include a sampling methodology that includes a representative sample from the lowest point in the tank.

5. Perform periodic (quarterly) sampling and analysis for water and sediment and the levels of microbiological organisms for the diesel generator fuel oil storage tanks (0A(B,C,D)T038).

6. Perform periodic (quarterly) sampling and analysis for particulate concentration and the levels of microbiological organisms for the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543).

7. Perform periodic (quarterly) trending of water and sediment content, particulate concentration, and the levels of microbiological organisms for all fuel oil tanks within the scope of the program.

8. Evaluate the need for biocide or corrosion inhibitor addition if periodic testing indicates biological activity or evidence of corrosion.

9. Evaluate degradation identified during tank internal inspections against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components’ intended function throughout the second period of extended operation based on the projected rate of degradation.

These enhancements will be implemented no later than six months prior to the second period of extended operation unless a more specific schedule is described within the enhancement (i.e., Enhancement 1). Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.20 Reactor Vessel Material Surveillance

The Reactor Vessel Material Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron irradiation embrittlement of the ferritic reactor pressure vessel (RPV) beltline materials in a reactor coolant and neutron flux environment. The program utilizes surveillance capsules that are located near the inside wall of the RPV beltline region in order to duplicate the neutron spectrum, temperature history, and neutron fluence of the RPV inner surface. The resulting lead factor allows the surveillance capsules to achieve a neutron fluence exposure earlier than the RPV allowing the surveillance capsules to be withdrawn and tested prior to the RPV reaching the neutron fluence of interest.

PBAPS, Unit 2 and Unit 3 are currently participating in an NRC approved integrated surveillance program (ISP) which covers the first period of extended operation. Unit 2 is a BWRVIP ISP host plant with three capsules in the vessel, one previously tested and reconstituted and two untested. The two untested capsules are scheduled to be withdrawn and tested during the first period of extended operation in accordance with the BWRVIP ISP. PBAPS Unit 3 is a BWRVIP ISP non-host plant with three capsules in the vessel, one previously tested and reconstituted and two untested. Unit 3 is not scheduled for withdrawal of any capsules during the first period of extended operation and relies on capsule test data from River Bend Nuclear Generating Station, Duane Arnold Energy Center, and the BWROG Supplemental Surveillance Program (SSP) in accordance with the BWRVIP ISP. The NRC has not approved an ISP for the second period of extended operation. For the second period of extended operation, the program will be enhanced to implement a reactor specific in-vessel program, complying with ASTM E 185-82, which will withdraw and test a surveillance capsule during the second period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the second period of extended operation. For boiling water reactors, the peak neutron fluence of interest is the 1/4T peak neutron fluence at the end of the second period of extended operation.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the second period of extended operation, and (b) provide adequate dosimetry monitoring during the operational period. A surveillance capsule will be withdrawn and tested from each reactor vessel during the second period of extended operation providing reactor vessel material irradiation embrittlement data and dosimetry monitoring during the second period of extended operation.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper-shelf energy as a function of neutron fluence and irradiation temperature. RPV beltline material test results provide reactor vessel material fracture toughness data for the neutron irradiation embrittlement time-limited aging analyses (TLAAs) (e.g., upper-shelf energy and pressure-temperature limits evaluations). The RPV beltline material surveillance capsules are removed at various exposure intervals for monitoring and trending purposes and in conjunction with the Neutron Fluence Monitoring (A.3.1.2) program. See Section A.4.2 for discussion of the TLAAs associated with neutron irradiation embrittlement.

Surveillance capsule are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H and ASTM E 185-82. Any changes to the surveillance capsule withdrawal schedule, including changing the status of standby capsules, must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or in-insertion.

The Reactor Vessel Material Surveillance aging management program will be enhanced to:

1. Withdraw and test the Unit 2, 120 degree reconstituted capsule and the Unit 3, 120 degree capsule per the capsule withdrawal schedules below. A technical summary report containing the test results shall be submitted to the NRC per the requirements of 10 CFR Part 50, Appendix H. Any changes to the Reactor Vessel Material Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.

Peach Bottom Unit 2 Capsule Withdrawal Schedule		
Capsule	Capsule Lead Factor (0T/¼T)	Capsule Withdrawal EFPY
30°	0.95/1.38	Per BWRVIP-86-R1-A
120°	0.95/1.38	7.53 (actual)
120° Reconstituted	0.95/1.38	60 - 62(1)
300°	0.95/1.38	Per BWRVIP-86-R1-A

1. Capsule 120° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.21 EFPY less than plant operating EFPY.

Peach Bottom Unit 3 Capsule Withdrawal Schedule		
Capsule	Capsule Lead Factor (0T/¼T)	Capsule Withdrawal EFPY
30°	0.95/1.38	7.57 (actual)
30° Reconstituted	0.95/1.38	Spare(1)
120°	0.95/1.38	60 - 62
300°	0.95/1.38	Spare(2)

1. Capsule 30° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating

EFPY.
2. Capsule 300° was withdrawn after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating EFPY.

This enhancement will be implemented in accordance with the schedules defined in the enhancement.

A.2.1.21 One-Time Inspection

The new One-Time Inspection aging management program is a condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the second period of extended operation; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program will include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the second period of extended operation.

Periodic inspections instead of this program will be used for structures or components with known age-related degradation mechanisms or when the environment in the second period of extended operation is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

This new aging management program will be implemented no later than 10 years prior to the second period of extended operation. The one-time inspections are required to be performed within the 10 years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.22 Selective Leaching

The Selective Leaching aging management program is a new condition monitoring program that will monitor components constructed of materials which are susceptible to selective leaching. Susceptible materials are gray cast iron, ductile iron, and copper alloys that contain greater than 15 percent zinc. Copper alloys containing greater than 8 percent aluminum (aluminum bronze) are also susceptible to selective leaching; however, there are no components in the scope of license renewal that are constructed of this material. The selective leaching program includes a one-time inspection for susceptible components exposed to closed cycle cooling water and treated water environment since plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments.

Visual inspections supplemented by mechanical examination techniques such as chipping or scraping (for ductile and gray cast iron components) will be conducted on a representative sample of susceptible components. In addition, periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, and soil environments. Inspections and tests will be conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the second period of extended operation. Inspections will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions as appropriate. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the second period of extended operation, additional inspections will be performed.

This new aging management program will be implemented no later than 10 years prior to the second period of extended operation. The one-time inspections are required to be performed within the 10 years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.23 ASME Code Class 1 Small-Bore Piping

The ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. Destructive examination methods may be used in lieu of volumetric examination. The program includes measures to verify that degradation is not occurring; thereby either to confirm that there is no need to further manage aging-related degradation or to validate the effectiveness of existing programs and practices for the second period of extended operation.

The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) that have experienced cracking and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking.

The only two instances of cracking of Class 1 small-bore piping occurred at socket welds on Unit 3 in 2005 and in 2017. The causes of these cracking conditions were effectively mitigated by design changes. There have been no Class 1 small-bore piping cracking events at Unit 3 butt welds or at Unit 2 socket welds or butt welds. For butt welds, the one-time inspection sample size will be three percent up to a maximum of 10 inspections for Unit 2 and Unit 3. Since there are 89 Unit 2 butt welds and 90 Unit 3 butt welds, three butt welds on Unit 2 and Unit 3 will be inspected. For socket welds, the one-time inspection sample size will be three percent up to a maximum of 10 on Unit 2, and 10 percent up to a maximum of 25 on Unit 3. Since there are more than 1000 socket welds on each Unit, 10 socket welds on Unit 2 and 25 socket welds on Unit 3 will be inspected. If destructive examination is used, then each weld receiving a destructive examination can be credited as equivalent to two volumetric examinations.

If cracking is revealed by a one-time inspection, then additional one-time inspections will be performed for the population of welds (butt welds or socket welds) that have experienced cracking in accordance with ASME Section XI, Subarticle IWB-2420; and periodic inspections will be performed in accordance with NUREG-2191, Table XI.M35-1, Category C.

This new aging management program will be implemented no later than six years prior to the second period of extended operation. The one-time inspections are required to be performed within the six years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.24 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material, cracking, and hardening and loss of strength for elastomeric components, loss of preload for HVAC closure bolting, and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic components, elastomers, and insulation jacketing (insulation when not jacketed) will be conducted. There are no cementitious components in the scope of this program. This program does not monitor for reduction of heat transfer due to fouling; this aging effect will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting

Components (A.2.1.25) program. This program does not manage cracking due to stress corrosion cracking (SCC) or loss of material in aluminum and SS components exposed to aqueous solutions and air environments containing halides. As discussed in SLRA Sections 3.1.2.2.16, 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.2, 3.3.2.2.4, 3.4.2.2.3, 3.2.2.2.8, 3.3.2.2.8, 3.4.2.2.7, 3.2.2.2.10, 3.3.2.2.10, and 3.4.2.2.9, these aging effects for these materials and environments are managed by the One-Time Inspection (A.2.1.21) program.

For certain materials, such as flexible polymers and elastomers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in scope component being operated below the dew point), will be periodically inspected every 10 years during the second period of extended operation. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures which include inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the second period of extended operation. Qualitative acceptance criteria will be defined to reasonably assure a singular decision is derived based on observed conditions.

This new aging management program will be implemented no later than six months prior to the second period of extended operation.

A.2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material and hardening and loss of strength of elastomeric materials. Reduction of heat transfer will also be managed. This program will consist of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, and other mechanical components. Applicable environments include condensation, closed cycle cooling water, diesel exhaust, fuel oil, lube oil, raw water, treated water, and waste water. Visual (VT-1) or surface examinations will be performed to detect cracking of stainless steel components exposed to a diesel exhaust environment. Except for hardening and loss of strength of elastomers, aging effects associated with components within the scope of the Open Cycle Cooling Water System (A.2.1.11) program, Closed Treated Water Systems (A.2.1.12) program, and Fire Water System (A.2.1.17) program will not be managed by this program. Loss of material due to recurring internal corrosion on the drain pans of the HPCI, RCIC, Core Spray and RHR pump room unit coolers will be managed by this program. Additionally, in accordance with NUREG-2191, AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”, loss of coating integrity for certain internally coated tanks in the Radwaste and Reactor Water Cleanup Systems will be performed by this program.

Internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the second period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 19 components per population per unit, where the sample size is not based on percentage of the population, will be inspected. Sample selection will consider component susceptibility to aging due to factors such as time in service and severity of operating conditions. Opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures which include inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria will insure that the component will meet its intended function until the next inspection or the end of the second period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

This new aging management program will be implemented no later than six months prior to the second period of extended operation.

A.2.1.26 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing condition monitoring program that provides monitoring of oil in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. The program provides reasonable assurance that the oil environment in the mechanical systems is maintained to the required quality, and the oil systems are maintained free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Program activities include sampling, analysis, and trending of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate in-leakage and corrosion product buildup.

A.2.1.27 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is an existing condition monitoring program that includes periodic inspection, testing, monitoring, and analysis of test coupons of the neutron-absorbing material in the spent fuel storage racks to assure that the required five percent sub-criticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material for visual appearance, dimensional measurements, weight, geometric changes (e.g., bubbling, blistering, corrosion, pitting, cracking, and flaking), and boron areal density as observed from coupons, to monitor for reduction of neutron absorbing capacity, loss of material, and change in dimension. This program is further described in UFSAR Section 10.3.6.2.

A.2.1.28 Buried and Underground Piping and Tanks

The Buried and Underground Piping and Tanks aging management program is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks including loss of material and cracking. It addresses piping and tanks composed of any material, including carbon steel and stainless steel.

The program also manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection). The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

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 second period of extended operation, an increase in the sample size will be conducted. If a reduction in the number of inspections recommended in NUREG-2191, AMP XI.M41, Table XI.M41-2 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the second period of extended operation.

The Buried and Underground Piping and Tanks aging management program will be enhanced to:

1. Manage cracking for buried stainless steel piping, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed exposing the base material.

2. Perform direct visual inspection of buried piping within the scope of license renewal in accordance with NUREG-2191, Table XI.M41-2, and sections 4.a and 4.b, during each 10-year period, beginning 10 years prior to the second period of extended operation. The number of inspections of buried piping will be based upon the as-found results of cathodic protection system availability and effectiveness. The length of piping for each inspection will be based on the recommendations in section 4.c.

3. Perform extent of condition inspections as follows: When measured pipe wall thickness, projected to the end of the second period of extended operation, does not meet the minimum pipe wall thickness requirements due to external environments, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse

indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-up inspections will be determined based on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval.

4. Upgrade existing cathodic protection system no later than 5 years prior to the second period of extended operation in accordance with NACE SP0169-2007 to ensure effective control of external corrosion of underground piping and tanks.

5. Perform examination of buried emergency diesel generator fuel oil tanks from the internal surface of the tank using volumetric techniques during each 10-year period, beginning 10 years prior to the second period of extended operation. A minimum of 25 percent coverage is required.

6. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping.

7. Apply coating to buried portions of the 10-inch diameter stainless steel line from the torus dewatering tank to the condensate transfer pump suction line in accordance with approved station specifications, during the 10-year period prior to the second period of extended operation.

These enhancements will be implemented no later than 10 years prior to the second period of extended operation, unless a more specific schedule is described within the enhancement (i.e., Enhancement 4). Inspections that are required to be performed in the 10-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.29 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program is a new condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, waste water, condensation, or lubricating oil that can lead to loss of material of base metals or downstream effects such as reduction in flow, pressure, or heat transfer when coatings/linings become debris. There are no piping or components with internal coatings/linings in the program scope that are exposed to closed-cycle cooling water, treated borated water, or fuel oil. This program is not used to manage the integrity of coatings applied to external surfaces of components.

This program manages these aging effects for internal coatings by conducting periodic visual inspections of all coatings/linings applied to the internal surfaces of in scope components where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s). Aging management of galvanized piping in the Plant Equipment and Floor Drain System, and internally coated tanks in the Radwaste and Reactor Water Cleanup Systems will be performed under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.1.25) program.

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. Baseline inspections not previously conducted will be performed in the 10-year period prior to the second period of extended operation. For non-cementitious coatings/linings, the training and qualification of individuals involved in coating/lining inspections, and the evaluation of inspection results, are conducted in accordance with ANSI and ASTM International Standards endorsed in RG 1.54, including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist, and should be limited to a few intact small blisters that are completely surrounded by sound material, and with size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

This new aging management program will be implemented no later than 10 years prior to the second period of extended operation. Baseline inspections that may be required in the 10-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.30 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of 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 surface examination to detect cracking for high temperature mechanical penetrations subject to cyclic loading but 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. Inspection results are compared with prior recorded results in acceptance of components for continued service.

The ASME Section XI, Subsection IWE aging management program will be enhanced to:

1. Perform surface examinations on accessible portions of high temperature drywell mechanical penetrations, in addition to visual examinations, to detect cracking, once per 10-year interval during the second period of extended operation.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.31 ASME Section XI, Subsection IWF

The ASME Section XI, Subsection IWF aging management program is an existing condition monitoring program that consists of periodic visual examinations of ASME Class 1, 2, 3, and MC piping and component supports and high-strength structural bolting for signs of degradation (such as loss of material, loss of mechanical function, cracking, and loss of preload), evaluation, and corrective actions. The program is implemented through corporate and station procedures, in accordance with the requirements of the ASME Code, Section XI, Subsection IWF, as approved in 10 CFR 50.55a. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. The program will be enhanced to implement additional inspections beyond the inspections required by the 10 CFR 50.55a ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection will be conducted within the five years prior to entering the second period of extended operation. 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 will be performed to detect cracking in addition to the VT-3 examination.

If a component support does not exceed the acceptance standards of IWF-3400 but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

The ASME Section XI, Subsection IWF aging management program will be enhanced to:

1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the second period of extended operation.

2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. Conduct the one-time inspection within the five years prior to entering the second period of extended operation. Select the additional supports from the remaining population of IWF piping supports. Ensure that the sample expansion includes components that are most susceptible to age-related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment).

3. Perform VT-3 examinations of all ASTM A-490 bolting materials, used for the reactor vessel support skirts and for the core spray pump supports once per 10-year interval during the second period of extended operation. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of 12 ASTM A490 bolts at each of the reactor vessel support skirts, once per 10-year interval during the second period of extended operation.

These enhancements will be implemented in accordance with the schedule described within the enhancements. Inspections that are required to be performed in the five-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.32 10 CFR Part 50, Appendix J

The 10 CFR 50 Appendix J aging management program is an existing condition monitoring program that consists of monitoring leakage rates through the containment system, its shell, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. Consistent with the current licensing basis, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, Option B, NEI 94-01, Revision 2-A and Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J", and subject to the requirements of 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants".

A.2.1.33 Masonry Walls

The Masonry Walls aging management program is an existing condition monitoring program that consists of visual inspections, based on IE Bulletin 80-11 and plant-specific monitoring proposed by IN 87-67, for managing shrinkage, separation, gaps, loss of material, and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

The Masonry Walls aging management program will be enhanced to:

1. Expand the program to include masonry walls in the Administration Building and Dewatering Building.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.34 Structures Monitoring

The Structures Monitoring aging management program is an existing condition monitoring program that consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, SEI/ASCE 11, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Structures are monitored on an interval not to exceed 5 years. Inspections also include seismic joint fillers, elastomeric materials; 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 sufficient detail, such as photographs and surveys for the type, severity, extent, and progression of degradation, to ensure that corrective actions can be taken prior to a loss of intended function. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative evaluation criteria of ACI 349.3R.

The Structures Monitoring aging management program will be enhanced to:

1. Explicitly include the following components and commodities within the scope of the program:

    a. Bearing pads for supports

    b. Electrical duct banks

    c. Electrical raceway such as cable tray, conduit, and wireway gutter

    d. Hatches and plugs

    e. Manholes and handholes

    f. Miscellaneous components such as louvers

g. Panels, racks, frames, cabinets, and other enclosures

h. Permanent shielding blankets

2. Add the following structures to the scope of the program:

   a. Administration Building

   b. Boiler House

   c. Dewatering Building

3. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation.

4. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R.

5. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified.

6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.

7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.

8. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant loss of material due to wear or corrosion, and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design.

9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to

such inaccessible areas

10. Expand the program to monitor elastomeric vibration isolators and bearing pads for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection to detect hardening, if the intended function is suspect. Establish acceptance criteria for elastomeric pads and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of isolation or support function.

11. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations.

12. Expand the program to inspect the fiberglass outer covering of permanent shielding blankets for signs of tears. If a tear is found, enter the condition into the corrective action program for evaluation. Repair or replace the permanent shielding, unless an evaluation determines that the condition is acceptable.

These enhancements will be implemented no later than six months prior to the second period of extended operation. Baseline inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.35 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is an existing condition monitoring program that consists of inspection and surveillance of the raw water control structures associated with emergency cooling systems, which are the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. The PBAPS design does not include dams, slopes, canals, and other raw water-control structures associated with emergency cooling water systems or flood protection in the scope of this program. The program includes reinforced concrete, structural steel, and structural bolting associated with the water-control structures. The program also includes PVC drift eliminators, ceramic tile fill, and cast iron fill supports at the Emergency Cooling Tower and Reservoir. In general, parameters monitored are in accordance with Section C.2 of RG 1.127 and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections are performed at least once every five years for structural components that are not submerged. Submerged components in the Circulating Water Pump Structure are inspected at least once every six years. Submerged components in the Emergency Cooling Tower and Reservoir are inspected at least once every 10 years. Structures exposed to aggressive water require additional plant-specific investigation.

Not included in this program is the offsite Conowingo Hydroelectric Plant (Dam), which is operated under a separate license and is subject to the FERC five-year inspection program. Aging management for the dam includes activities such as visual inspections by a qualified independent consultant approved by FERC, and submittal of inspection reports with corrective actions that are approved by FERC. Aging management for the dam is performed in accordance with FERC requirements, and is in compliance with Title 18 of the Code of Federal Regulations, Conservation of Power and Water Resources, Part 12 (Safety of Water Power Projects and Project Works), Subpart D (Inspection by Independent Consultant). The inspections performed under the FERC five-year inspection program, called the FERC Inspections of the Conowingo Hydroelectric Plant (Dam) (Appendix A.5, Commitment 50), have been accepted by FERC, and are the current licensing basis for PBAPS regarding aging management of the dam. PBAPS will continue to comply with these FERC requirements during the second period of extended operation.

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to:

1. Explicitly include the sluice gates at the Circulating Water Pump Structure within the scope of the program.

2. Clarify parameters to be monitored and inspected at the Emergency Cooling Tower and Reservoir to include visual inspection for loss of material and reduction of heat transfer due to fouling for the cooling tower fill, and visual inspection of the drift eliminators.

3. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified.

4. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt.

5. Include provisions for special inspections following significant natural phenomena, such as large floods, hurricanes, tornadoes, or intense local rainfall as part of the guidelines for severe weather and natural disasters.

6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.

7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement

degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.

8. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

9. Document the concrete conditions of submerged concrete structures.

10. Specify a six-year frequency for the inspection of the submerged portions of the traveling screen bays to match the inspection frequency of the submerged portions of the Circulating Water Pump Structure bays.

11. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation.

12. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R.

13. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations.

These enhancements will be implemented no later than six months prior to the second period of extended operation. Baseline inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.36 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance aging management program is an existing mitigative and condition monitoring program that manages the effects of loss of coating integrity of Service Level I coatings inside primary containment. The program manages coating system selection, application, visual inspections, assessments, repairs, and maintenance of Service Level I protective coatings as defined in RG 1.54, Revision 1 or latest revision.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel containment and torus shell, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment shells and components. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

The Protective Coating Monitoring and Maintenance aging management program will be enhanced to:

1. Use certified coating inspectors for the inspection of Service Level I coatings.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.2.1.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of electrical insulation for license renewal in scope, non-EQ, electrical cables and connections during the second period of extended operation.

In most areas of PBAPS, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. An adverse localized environment (ALE) is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected in these adverse localized environments.

Accessible cables and connections located in adverse localized environments are managed by visual inspection. These cables and connections are visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture. This is an adequate inspection frequency to preclude failures of the cable and connection insulation since experience shows that aging degradation is a slow process.

Additional inspections, repairs, or replacements are initiated as appropriate under the corrective action program. If visual inspections identify degraded or damaged conditions that may impact the cable system’s ability to perform its intended functions, then testing may be performed for evaluation. Testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Testing as part of an existing maintenance, calibration or surveillance program may be credited. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the station's procedures.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced to:

1. Include potential follow-up actions when visual inspections identify degraded or damaged conditions that may impact the performance of intended functions:

    a. Perform tests, for condition monitoring when visual inspections identify damaged or degraded insulation of in scope cables and connections. When a large number of cables are identified as damaged or degraded, a sample population will be tested. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25.

    b. Document the basis for the sample selected for testing when visual inspections identify damaged or degraded insulation conditions for in scope cables and connections.

2. Visually inspect and evaluate cables and connections that were exposed to adverse localized environments (ALEs), which have since been mitigated, on an at least once every 10-year frequency, to assure the cumulative aging effects for electrical insulation, in remedied ALEs are not impacting the ongoing ability of the cables and connections to perform their intended function during the second period of extended operation.

These enhancements will be implemented no later than six months prior to the second period of extended operation. In addition, the first inspections incorporating enhancements will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is an existing performance monitoring program that will manage the effects of reduced insulation resistance of non-EQ cable and connection electrical insulation in instrumentation circuits with sensitive, high voltage, low-level current signals. The program applies to the in scope portions of the Neutron Monitoring System and the Radiation Monitoring System, that are located in areas with potential adverse environments and are not managed by the Environmental Qualification of Electric Equipment (A.3.1.3) program. The adverse localized environments are caused by temperature, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance causing increases in leakage currents. Other instrument circuits in the Neutron Monitoring System and Radiation Monitoring System are not in scope of this aging management program either because they do not perform a license renewal intended function; they are not sensitive high voltage, low-level signal circuits; or they are managed by the Environmental Qualification of Electric Equipment (A.3.1.3) program.

Calibration or surveillance testing will be performed for the in scope circuits when the cables are included as part of the calibration or surveillance circuit. The calibration and surveillance results will be periodically reviewed to provide an indication of the existence of aging effects based on acceptance criteria for instrumentation circuit performance. Review of results obtained during normal calibration and surveillance may detect severe aging degradation prior to the loss of the cable and connection intended function. A proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed for the in scope circuits when the cables are not included as part of the calibration or surveillance or as an alternative to the review of calibration or surveillance results.

Periodic review of calibration or surveillance results will first be performed prior to the second period of extended operation and at least once every 10 years during the second period of extended operation. If cable tests are credited for program implementation, cable test frequency will be based on engineering evaluation and will be performed at least once every 10 years.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program will be enhanced to:

1. Add the following radiation monitors to the scope of this program
    a. Main steam line radiation monitors
    b. Reactor building ventilation exhaust radiation monitors
    c. Control room fresh air supply radiation monitors
    d. Control room emergency ventilation supply radiation monitors
    e. Main stack radiation monitors.

2. 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. Perform the first periodic review for second license renewal prior to the second period of extended operation and at least every 10 years thereafter.

These enhancements will be implemented no later than six months prior to the second period of extended operation. The first documented periodic review will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), medium voltage power cables (operating voltage; 2 kV to 35 kV), exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance of the cable’s insulation system due to wetting or submergence, such as dielectric loss (dissipation factor or power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state of the art at the time the test is performed. The first tests will be completed prior to the second period of extended operation. The cables will be tested at least once every six years thereafter. More frequent testing may occur based on test results and operating experience.

Submarine or other cables designed for continuous wetting or submergence are also included in this program as a one-time test with additional periodic tests and inspections determined by one-time inspection results and industry and plant-specific operating experience.

Periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the inspections will occur either at least once per year or at least once every five years for manholes with level monitoring, alarms, and subsequent pump-out prior to wetting or submergence of cables.

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced to:

1. Add periodic cable testing for additional circuits.

2. Perform cable testing of the circuits in the scope of this program at a frequency of at least once every six years.

3. Add periodic condition monitoring, as a preventive action, for manholes.

These enhancements will be implemented no later than six months prior to the second period of extended operation. Tests and inspections that are required to be performed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.40 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

A sample of in scope, inaccessible instrument and control cables, potentially exposed to significant moisture, will be tested in a one-time confirmatory effort. The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance. The tests will be performed prior to the second period of extended operation. The in scope inaccessible instrument and control cables, potentially exposed to significant moisture, will also be visually inspected to identify if observable age degradation of the electrical insulation is occurring. The visual inspection will be performed for cables and connections that are accessible during manhole inspections. The visual inspections will occur at least once every six years co-incident with manhole inspections that are being performed at least once every year or at least once every five years. The first visual inspection of inaccessible instrument and control cables will be completed prior to the second period of extended operation.

There are no current submarine or other cables designed for continuous wetting or submergence in the scope of this program. Future cables of this design would be considered for inclusion in this program.

Periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the manhole inspections will be performed either at least once every year or at least once every five years based on operating experience of individual manhole level monitoring and pump out activities.

This new aging management program will be implemented no later than six months prior to the second period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.41 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low voltage power cables (operating voltage less than 2 kV), exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

In scope, inaccessible low voltage power cables, potentially exposed to significant moisture, will be tested in a one-time confirmatory effort. The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance. The tests will be performed prior to the second period of extended operation. The in scope inaccessible low voltage power cables, potentially exposed to significant moisture, will also be visually inspected to identify if observable age degradation of the electrical insulation is occurring. The visual inspection will be performed for cables and connections that are accessible during manhole inspections. The visual inspections will occur at least once every six years co-incident with manhole inspections that are being performed at least once every year or at least once every five years. The first visual inspection of inaccessible low voltage power cables will be completed prior to the second period of extended operation.

There are no current submarine or other cables designed for continuous wetting or submergence in the scope of this program. Future cables of this design would be considered for inclusion in this program.

Periodic actions are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the manhole inspections will be performed either at least once every year or at least once every five years based on operating experience of individual manhole level monitoring and pump out activities.

This new aging management program will be implemented no later than six months prior to the period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.42 Metal Enclosed Bus

The Metal Enclosed Bus aging management program is a new condition monitoring program that uses sampling and will manage the identified aging effects of in scope metal enclosed bus. The internal portions of the accessible bus enclosure assemblies will be visually inspected for age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation will be visually inspected for signs of reduced insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination which may indicate overheating or aging degradation. The internal bus insulating supports will be visually inspected for structural integrity and signs of cracks. External surfaces in an air-outdoor environment will be visually inspected for loss of material due to general, pitting, and crevice corrosion. There are no gaskets, boots, and sealants as part of the external portions, including access panels, for the in scope metal enclosed buses; therefore, there will be no aging management activities for elastomers in this aging management program.

A sample of accessible bolted connections will be inspected for increased resistance of connection by either performing thermography or measuring the connection resistance using a micro-ohmmeter. In addition to thermography or resistance measurement, bolted connections not covered with heat shrink tape or boots are visually inspected for increased resistance of connection (e.g., loose or corroded bolted connection and hardware including cracked or split washers).

The inspections and resistance measurements will be performed prior to second period of extended operation and at least once every 10 years for indications of aging degradation.

This new aging management program will be implemented no later than six months prior to the second period of extended operation. Initial inspections and resistance measurements will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.1.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that consists of a representative sample of electrical connections tested prior to the second period of extended operation. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency. The program applies to electrical connections within the scope of second license renewal that are not subject to EQ requirements. The following factors are considered for sampling: voltage level (medium and low-voltage), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of each connector type population with a maximum sample of 25 constitutes a representative connector sample size. The specific type of test to be performed shall be a proven method for detecting increased resistance of the connection.

The program does not implement visual inspections of cable connection insulation materials as an alternative to thermography.

This new aging management program will be implemented no later than six months prior to the second period of extended operation. Testing and evaluation of results will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.2.2 Plant-Specific Aging Management Programs

This section provides summaries of the plant-specific programs credited for managing the effects of aging.

A.2.2.1 Wooden Pole

The Wooden Pole aging management program is an existing condition monitoring program that manages aging effects associated with the wooden pole adjacent to the Susquehanna Substation. The wooden pole provides the structural support for the conductors connecting the substation to the submarine cable for the alternate AC power for PBAPS's station blackout coping period. There are no preventive or mitigative actions associated with this program. The program manages loss of material and change in material properties by conducting periodic inspections in accordance with corporate specifications of the wooden pole within the scope of the program. Periodic inspections are conducted on a 10-year frequency. Inspection activities consist of visual inspections, sounding, boring, and excavation, as required, to ensure an adequate examination. Acceptance criteria outlined in the corporate specifications ensure appropriate corrective actions are taken based on observed conditions. If an inspection identifies a degraded condition associated with the wooden pole, the corrective action program is utilized to facilitate repair or replacement activities.

The Wooden Pole aging management program will be enhanced to:

1. Document results that do not meet the acceptance criteria in the corrective action program.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.3.0 NUREG-2191 Chapter X Aging Management Programs

A.3.1 Evaluation of Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-2191 are associated with Time-Limited Aging Analysis for metal fatigue of the reactor coolant pressure boundary and environmental qualification (EQ) of electric components. These programs are evaluated in this section.

A.3.1.1 Fatigue Monitoring

The Fatigue Monitoring aging management program is an existing preventive program that manages fatigue damage of the reactor pressure vessel components, reactor coolant pressure boundary piping components, and other components per 10 CFR 54.21(c)(1)(iii). The program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable cumulative usage fatigue (CUF) analyses and environmental-assisted cumulative usage fatigue (CUF_{en}) analyses. No PBAPS ANSI B31.1 and ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to these implicit analyses. No ASME Section III fatigue waiver analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to fatigue waiver analyses. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth, flaw tolerance, or fracture mechanics analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components by monitoring for design transient cycles and the calculating CUF values and CUF_{en} values. The program also monitors applicable plant-specific parameters (e.g., temperatures, pressures, flow rates, etc.) used in stress-based fatigue analysis methodologies. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth, flaw tolerance, or fracture mechanics analyses. The program utilizes applicable acceptance criteria (limits) to verify the continued acceptability of existing analyses through transient cycle counting and the calculation, trending, and projection of CUF and CUF_{en} values. The program verifies the continued acceptability of existing analyses with periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

When a program acceptance criterion is exceeded or the severity an actual transient exceeds the design transient definition the condition is entered into the corrective action program and appropriate corrective actions, such as reanalysis, component or structure inspections, or component or structure repair or replacement activities are implemented to ensure that design limits are not exceeded. The program manages cumulative fatigue damage in accordance UFSAR Section 4.2.5 and Tech Spec Section 5.5.5.

The Fatigue Monitoring aging management program will be enhanced to:

1. Update the SI:FatiguePro™ software to include the calculation and tracking of Environmentally Assisted Fatigue (EAF) in accordance NUREG/CR-6909, Revision 1.

2. Update applicable fatigue analyses and monitored component locations based on operating experience, plant modifications, inspection findings, changes to transient definitions, and unanticipated newly discovered fatigue loading events.

3. Provide procedural direction to require periodic validation of chemistry parameters used to determine Fen factors used in SI:FatiguePro™.

4. Provide procedural direction to add an additional acceptance criterion associated with HELB exclusion criteria.

These enhancements will be implemented no later than six months prior to the second period of extended operation.

A.3.1.2 Neutron Fluence Monitoring

The Neutron Fluence Monitoring aging management program is an existing condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits. The components evaluated by these analyses are the reactor pressure vessel shell and welds and reactor vessel internal components subject to reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC approved reports. The methods and assumptions for projecting RPV neutron fluence for the beltline region are consistent with U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The methods and assumptions used for the original beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of 1×10^{17} n/cm^2 (E > 1 MeV) at 70 EFPY, since the extended region does not extend significantly above or below the active fuel region and no additional reactor vessel plate materials (heat numbers) or welds are projected to experience fluence in excess of 1×10^{17} n/cm^2 (E > 1 MeV). The methods for projecting reactor vessel internal component fast neutron fluence values are not governed by regulatory guidance or requirements.

The program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor pressure vessel components. This includes but is not limited to the neutron fluence inputs for the reactor pressure vessel upper-shelf energy analyses (or equivalent margin analyses, as applicable to the CLB) and pressure-temperature limits analyses that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) include those for mean RT_{NDT} and probability of failure analyses for BWR reactor pressure vessel circumferential and axial shell welds, BWR core reflood design analyses, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance (A.2.1.20) program provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

The Neutron Fluence Monitoring aging management program will be enhanced to:

1. Perform periodic monitoring of reactor pressure vessel and reactor vessel internals accumulated neutron fluence, every refueling cycle, to ensure that neutron fluence projections used to support reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs, pressure-temperature limits) and reactor vessel internals aging effect assessments remain bounding with respect to actual plant operating conditions.

This enhancement will be implemented no later than six months prior to the second period of extended operation.

A.3.1.3 Environmental Qualification of Electric Equipment

The Environmental Qualification of Electric Equipment aging management preventive program is an existing program that ensures maintenance of qualified life and TLAA analyses for the electrical equipment important to safety within the scope of 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants.” An aging limit (qualified life) is established for equipment within the scope of the program and an appropriate action such as replacement, refurbishment, or reanalysis is taken prior to or at the end of the equipment qualified life so that the aging limit is not exceeded. Changes to material activation energy values as part of a reanalysis are justified. The program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to apply the qualification conclusions and the equipment qualified life.

The Environmental Qualification of Electric Equipment aging management program will be enhanced to:

1. Add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the second period of extended operation.

2. Establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments.

These enhancements will be implemented no later than six months prior to the second period of extended operation. New visual inspections of accessible, passive EQ equipment located in adverse localized environments will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.

A.4.0 Time-Limited Aging Analyses

A.4.1 Identification and Evaluation of Time-Limited Aging Analyses

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the period of extended operation be provided. The TLAAs identified and evaluated to meet these requirements are described below.

10 CFR 54.21(c)(2) also requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the period of extended operation. No plant-specific exemptions granted pursuant to 10 CFR 50.12 were identified for PBAPS that are based upon a TLAA. Therefore, no further evaluation is required for plant-specific exemptions granted pursuant to 10 CFR 50.12.

A.4.2 Reactor Vessel and Internals Neutron Embrittlement Analyses

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The current reactor pressure vessel embrittlement calculations for PBAPS that evaluate reduction of fracture toughness of the Units 2 and 3 reactor pressure vessel beltline materials for 60 years are based upon a predicted end-of-license fluence applicable for 54 Effective Full Power Years (EFPY). These analyses have been identified as TLAAs as defined in 10 CFR 54.21(c) and have been reevaluated for the increased neutron fluence associated with 80 years of operation as described in the subsections below. These subsections also include evaluations of the increased neutron fluence on reactor internal components, including potential loss of preload for the core plate rim hold-down bolts, jet pump slip joint clamps, jet pump auxiliary spring wedge assemblies, and jet pump riser clamps; as well as irradiation-enhanced stress relaxation of the replacement core plate extended life plugs.

A.4.2.1 Reactor Vessel and Internals Neutron Fluence Analyses

High energy (>1 MeV) neutron fluence has been projected for 80 years and 70 Effective Full Power Years (EFPY). The fluence projections have been used in the evaluation of the neutron embrittlement TLAAs. Two different methodologies have been used in developing the projections as described below.

- The NRC approved General Electric Hitachi (GEH) Discrete Ordinates Transfer (DORT) methodology has been used in developing the fluence projections and associated reactor vessel embrittlement analyses as documented in Sections A.4.2.1.1, and A.4.2.2 through A.4.2.7.

- Transware Radiation Analysis Modeling Application (RAMA) methodology has been used to develop 80-year fluence projections for reactor vessel internal components that are used in evaluating reactor vessel internal component TLAAs in Sections A.4.2.1.2, and A.4.2.8 through A.4.2.12.

There has been no combination of the two methodologies applied to any component. Below is a summary of PBAPS historical operating power levels which have been considered in developing both 80-year fluence projections:

- The Original Licensed Thermal Power (OLTP) level for PBAPS Units 2 and 3 was 3293 MWt.
- By Amendment Nos. 198 and 211 (Units 2 and 3 respectively), the NRC approved an approximate 5.0 percent stretch power uprate to 3458 MWt in the mid-1990s.
- By Amendment Nos. 247 and 250 (Units 2 and 3, respectively) dated November 22, 2002, the NRC approved a 1.62 percent measurement uncertainty recapture (MUR) uprate that authorized an increase in the maximum thermal power level from 3458 MWt to 3514 MWt.
- By Amendment Nos. 293 and 296 dated August 25, 2014, the NRC approved a 12.4 percent EPU (Extended Power Uprate) that authorized an increase in the maximum thermal power level from 3514 MWt to the licensed thermal power level of 3951 MWt for both units.
- By Amendment Nos. 305 and 309, March 21, 2016 the NRC approved a Maximum Extended Load Line Limit Analysis Plus (MELLA+) operating strategy in 2016 in accordance with NEDC-33006P-A for both units.
- By Amendment Nos. 316 and 319 dated November 15, 2017, the NRC approved a 1.66 percent Measurement Uncertainty Recapture (MUR) power uprate to 4016 MWt at mid-Cycle 22 for Unit 2 and at the beginning of Cycle 22 for Unit 3.

The current uprated power level of 4016 megawatts thermal (MWt) is the maximum power level evaluated for the second period of extended operation.

A.4.2.1.1 Reactor Vessel Neutron Fluence Analyses

Reactor vessel fluence projections for 80 years and 70 EFPY have been developed using the NRC approved General Electric Hitachi (GEH) Discrete Ordinate Transfer (DORT) methodology. The GEH methodology adheres to the guidance in Regulatory Guide 1.190 for neutron flux evaluation. The 70 EFPY fluence projection values have been used in the evaluation of the neutron embrittlement TLAAs for reactor vessel beltline materials, which include the reactor vessel plate materials, welds, and nozzle forgings. Fluence projections have been developed to evaluate fluence-based reactor vessel TLAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

These 70 EFPY fluence projections will be validated by the Neutron Fluence Monitoring (A.3.1.2) aging management program during the second period of extended operation.

The Unit 2 and Unit 3 RPV beltline component fluence analyses have been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.1.2 Reactor Vessel Internals Neutron Fluence Analyses

Fluence projections have been developed for 80 years and 70 EFPY for reactor vessel internal components using the Transware Radiation Analysis Modeling Application (RAMA) Fluence Methodology. Use of this model was performed in accordance with NRC Regulatory Guide 1.190. The fluence projections have been developed for specific reactor vessel internal components to evaluate fluence-based TLAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

The Unit 2 and Unit 3 reactor vessel internal component fluence analyses have been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.1.3 RPV Supplemental Metallurgical Sensitivity Evaluation

The RPV extended beltline elevations are the upper and lower elevations bounding the region of the RPV vessel where fluence values are projected to equal or exceed 1.0E+17 n/cm2.

NUREG-2192 and 10 CFR 50.60 recommend fracture toughness evaluations of RPV components which are projected to experience fluence values of 1.0E+17 n/cm^2 or more. RPV fluence and upper extended beltline elevation projections for 80 years at 70 EFPY were performed using the GEH DORT methodology as described in Section A.4.2.1.1. Fracture toughness evaluations of RPV components within the extended beltline elevations are described in Section A.4.2.2 through A.4.2.7.

The Neutron Fluence Monitoring aging management (A.3.1.2) program is an existing condition monitoring program that monitors and tracks neutron fluence to RPV components to ensure that fluence projections described on Section A.4.2.1.1 remain valid through second period of extended operation.

Sensitivity evaluations have been performed to address a recent NRC concern that fluence projections above the active fuel region may have greater uncertainty than fluence projections for RPV elevations within the active fuel region. The concern is that water density sensitivity analyses described in Section 7.1, “Calculation Uncertainties,” of NEDC-32983P-A, Revision 2, are not applicable to the above core water density distribution because the generically approved calculational model does not extend above the active fuel region based on Figure 2-2 of in NEDC-32983P-A, Revision 2. Also, projected fluence results for RPV elevations above the active fuel have not been benchmarked. Non-conservative fluence projections could potentially result in a non-conservatively low upper extended beltline elevation and exclude the metallurgically evaluation of portions of the RPV that will actually be exposed to 1.0E+17 n/cm^2 or more, prior to the end of the period of extended operation.

Because of this uncertainty, work is ongoing with the ANS 19.10 standards committee to revise the guidance within RG 1.190 to more explicitly outline its expectations for fluence projections within the upper plenum. In addition, the sensitivity evaluations discussed below have been performed to provide reasonable assurance that all components that may experience fluence values of 1.0E+17 n/cm^2 or more, meet established metallurgical acceptance criteria.

As shown on Figure 4.2.1-1, for Unit 2, the calculated 70 EFPY upper extended beltline elevation of approximately 383 inches resulted in the successful metallurgical evaluation of: all the lower-intermediate vessel wall plates, all the lower vessel wall plates, all the V1A/B/C and all V2A/B/C axial welds, the H2 circumferential weld, and the N16 nozzles, as described in Sections A.4.2.2 through A.4.2.7.

The Unit 2 intermediate plates, the H3 circumferential weld, and V3 axial welds are located 9 inches (elevation 392 inches) above the upper extended beltline elevation and have not been metallurgical evaluated in Sections A.4.2.2 through A.4.2.7. Although it is not reasonable that the uncertainty associated with the NRC's concern would result in the extension of the upper extended beltline elevation for an additional 9 inches (elevation 392 inches) at 70 EFPY, a supplemental metallurgical sensitivity evaluation and justification was performed on all the Unit 2 intermediate plates, the H3 circumferential weld, and all V3A/B/C axial welds. Results of the supplemental metallurgical sensitivity evaluation concluded that, even with a postulated fluence value that is more than 20 times greater than expected, these reactor vessel components meet all the established metallurgical acceptance criteria for ART, USE/EMA, circumferential weld inspection relief, axial weld probability, and reflood thermal shock.

As shown on Figure 4.2.1-2, the Unit 3 lower-intermediate plates, are 38 inches shorter than the Unit 2 lower-intermediate plates. As a result, the Unit 3 projected upper extended beltline (elevation 383 inches) extends onto portions of the intermediate plates and V3A/B/C welds and envelops the Unit 3 H3 weld, while for Unit 2 the upper extended beltline elevation does not reach these components. Therefore, for Unit 3, the calculated 70 EFPY upper extended beltline elevation resulted in the successful metallurgical evaluation of: all the intermediate vessel wall plates, all the lower-intermediate vessel wall plates, all the lower vessel wall plates, all the V1A/B/C, V2A/B/C, and V3A/B/C axial welds, the H2 and H3 circumferential weld, and the N16 nozzles, as described in Sections A.4.2.2 through A.4.2.7.

Unlike the Unit 2 intermediate plates, V3A/B/C welds, and H3 weld, which are located above the Unit 2 upper extended beltline elevation of 383 inches and therefore excluded from fracture toughness evaluation described in Sections

A.4.2.2 and through A.4.2.7, the Unit 3 intermediate plates and V3A/B/C welds which extend above elevation 443 inches, and H3 weld located at elevation 335 inches are evaluated for fracture toughness as described in Sections A.4.2.2 and through A.4.2.7. Nevertheless, because of the uncertainty associated with the NRC's concern, a supplemental metallurgical sensitivity evaluation and justification was performed on all the Unit 3 intermediate plates and associated welds. Results of the supplemental metallurgical sensitivity evaluation concluded that, even with a postulated fluence value that is more than 20 times greater than expected, these reactor vessel components meet all the established metallurgical acceptance criteria for ART, USE/EMA, circumferential weld inspection relief, axial weld probability, and reflood thermal shock.

The supplemental metallurgical sensitivity evaluation does not introduce additional Unit 2 and 3 RPV components, that require fracture toughness evaluation per the recommendations in NUREG-2192 and 10 CFR 50.60. The supplemental metallurgical sensitivity evaluation serves as an analysis and justification that provides reasonable confidence that RPV components above approximately 383 inches would meet the established metallurgical acceptance criteria should future industry resolution of the concern result in the extension of the upper extended beltline elevation by more than 9 inches.

The Unit 2 and Unit 3 N9 nozzles are the lowest RPV components above the upper extended beltline elevation that have not been metallurgically evaluated in section A.4.2.2 through A.4.2.7 or in the supplemental metallurgical sensitivity evaluation. These are single 4-inch Control Rod Drive Hydraulic System Return nozzles located approximately 60 inches (elevation 443 inches) above the established upper extended beltline elevation of approximately 383 inches. It is not credible that the uncertainty associated with the NRC's concern would result in an extension of the upper extended beltline elevation for an additional 60 inches (elevation 443 inches).

This NRC concern has been entered in to the PBAPS corrective action program. Results from industry activities associated with the ANS 19.10 standards committee will be incorporated into the Neutron Fluence Monitoring aging management (A.3.1.2) program as appropriate.

Note: all RPV elevations are based on Reactor Vessel Elevation "0" at the bottom head drain and are rounded to nearest inch.

A.4.2.2 Reactor Vessel Upper-Shelf Energy (USE) Analyses

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The PBAPS Units 2 and 3 reactor vessels were designed and fabricated prior to the current requirements, and as a result, there is insufficient data available to establish the initial unirradiated USE value for all beltline materials for these reactor vessels. Therefore, the current licensing basis Charpy USE evaluations are based upon Equivalent Margin Analysis (EMA) as specified in BWRVIP-74-A, which meets the alternative requirements specified above. The PBAPS Units 2 and 3 February 2017 MUR amendment submittal reevaluated EMA for 60 years and 54 EFPY fluence values. Therefore, these analyses have been identified as TLAAs requiring evaluation for the second period of extended operation.

An EMA has been performed for the limiting beltline plate and weld materials for 80 years of operation at 70 EFPY, and then compared against the 54 EFPY limits defined in Appendix B of BWRVIP-74-A. The comparison concluded that the Units 2 and 3 vessel materials meet the 54 EFPY limits defined in Appendix B of BWRVIP-74-A and the USE values for Unit 2 and Unit 3 reactor vessel beltline materials have been satisfactorily evaluated for the second period of extended operation based upon the updated EMA values determined using 80-year (70 EFPY) fluence projections. Therefore, the Equivalent Margins Analyses have been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.3 Reactor Vessel Adjusted Reference Temperature (ART) Analyses

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the P-T limit curves to account for irradiation effects. The initial nil-ductility reference temperature (RT_{NDT}) is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Code. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) determines how much higher the vessel temperature must be raised for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + ΔRT_{NDT} + Margin. The PBAPS Units 2 and 3 February 2017 MUR amendment submittal reevaluated the adjusted reference for 60 years and 54 EFPY fluence values. Therefore, these analyses have been identified as TLAAs requiring evaluation for the second period of extended operation.

70 EFPY ART values have been determined for PBAPS Units 2 and 3 beltline materials using the methodology specified in Regulatory Guide 1.99, Revision 2. The 70 EFPY ART values of the limiting beltline materials for each unit remain below 200 degrees F, which is the RT_{NDT} limit.

The 70 EFPY ART analyses have been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(ii).

A.4.2.4 Reactor Vessel Pressure-Temperature (P-T) Limits

10 CFR 50 Appendix G requires that the reactor pressure vessel be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the reactor pressure vessel is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated reactor vessel fluence.

The current Pressure-Temperature limit curves are located in a Pressure-Temperature Limits Report and are based upon 53 EFPY fluence projections that were considered to represent the amount of power to be generated over 60 years of plant operation under MUR conditions. The currently licensed P-T curves were developed for up to 54 EFPY at the EPU power level of 3951 MWt. The 54 EFPY MUR analyses resulted in a minor increase in adjusted reference temperature (ART) of less than 0.5 degrees F at a few beltline locations. These minor increases slightly exceed a few of the ART values assumed for the currently licensed P-T curves. Therefore, currently licensed P-T curves have been evaluated for MUR conditions and concluded to be valid for up to 53 EFPY at the MUR power level of 4016 MWt. The P-T limits have been identified as TLAAs requiring evaluation for the second period of extended operation.

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the second period of extended operation will be updated at the appropriate time through the plant’s Administrative Section of the PBAPS Technical Specification 5.6.7, “Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)” and the plant’s PTLR process. This process will ensure that the P-T limits for the second period of extended operation will be updated prior to expiration of the 53 EFPY P-T limit curves.

Therefore, the effects of aging on the intended function(s) of the reactor vessels will be adequately managed through the second period of extended operation, as described in Technical Specification 5.6.7, in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.5 Reactor Vessel Circumferential Weld Failure Probability Analyses

PBAPS has previously applied for and been granted relief from RPV circumferential weld inspection for the Units 2 and 3 vessels. The relief from inspection is based on assessment of the probability of failure of the limiting circumferential weld. This assessment is based on 54 EFPY fluence values associated with 60 years of operation, and has therefore been identified as a TLAA requiring evaluation for the second period of extended operation.

In order to evaluate the PBAPS Units 2 and 3 circumferential weld failure probability for 80 years, 70 EFPY fluence values have been projected for each circumferential weld and mean RT_{NDT} values have been then determined. The mean RT_{NDT} values have been compared to circumferential weld probability analysis at 64 EFPY specified in the NRC’s Final Safety Evaluation Report

(FSER) of BWRVIP-05. The PBAPS mean RT_{NDT} values based on 70 EFPY are significantly less than the NRC RT_{NDT} values based on 64 EPFY used in determining the conditional failure probability in NRC's FSER of BWRVIP-05 dated July 28, 1998. Therefore, the NRC conditional failure probability is bounding for PBAPS Units 2 and 3, consistent with the requirements defined in GL 98-05.

Reapplication for relief from circumferential weld examination will be made in accordance with 10 CFR 50.55a(a)(3) in time for NRC review and approval prior to the second period of extended operation. The plant-specific information described above demonstrates that at the end of the second period of extended operation, the circumferential beltline weld materials meet the limiting conditional failure probability for circumferential welds specified in the NRC's FSER of BWRVIP-05. These analyses will be managed in accordance with 10 CFR 54.21(c)(1)(iii) by requesting relief from circumferential weld inspection using the 10 CFR 50.55a process.

A.4.2.6 Reactor Vessel Axial Weld Failure Probability Analyses

The BWRVIP recommendations for inspection of reactor pressure vessel shell welds in 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 Staff 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 Staff failure probability assessments are applicable to PBAPS Units 2 and 3, they are identified as TLAAs requiring evaluation through the second period of extended operation.

In order to evaluate axial weld failure probability analyses for 80 years for the PBAPS Units 2 and Unit 3 vessels, 70 EFPY fluence projections have been developed for the inside surface of the limiting axial welds. Using the bounding inside surface fluence value, the mean RT_{NDT} values have been determined for these welds, where the mean RT_{NDT} value does not include the margin term (M) described in RG 1.99, Revision 2, consistent with the evaluation methodology described in Section 2.1 of the March 7, 2000 supplement to the final safety evaluation.

The limiting PBAPS Units 2 and 3 axial weld mean RT_{NDT} values at 70 EFPY (without margin) are bounded by the mean RT_{NDT} values (without margin) determined for the limiting reactor in the March 7, 2000 supplement to the final safety evaluation. Therefore, the NRC's calculated RPV failure frequency of 5.02E-06 due to failure of limiting axial welds in the BWR fleet, is bounding for PBAPS Units 2 and 3. Therefore, this analysis has been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.7 Reactor Vessel Reflood Thermal Shock Analysis

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 boiling water reactors, this requirement is demonstrated both by development of Pressure-Temperature Limit Curves, which are addressed in Section A.4.2.4, and by reference to a generic fracture mechanics analysis that evaluates the effects of the limiting Loss of Coolant Accident (LOCA) event.

The generic fracture mechanics analysis evaluates the effects of a postulated LOCA on the structural integrity of a reactor pressure vessel. The rupture of a main steam line was determined to bound all other LOCA events with respect to this evaluation. After the rupture, several emergency core cooling systems are activated at different times and the vessel is flooded with cooling water. The vessel depressurization and the subsequent injection of cold water to reflood the reactor vessel produce a rapid reduction in temperature and high thermal stresses in the vessel. The analysis concludes that the reactor pressure vessel has a considerable margin to failure by brittle fracture even in the presence of postulated pre-existing flaws. This generic analysis envelopes PBAPS and is based on BWR vessel material properties and cumulative fluence assumed for 40 years of operation. The PBAPS Units 2 and 3 February 2017 MUR amendment submittal reevaluated the RPV reflood thermal shock analysis for 60 years and 54 EFPY fluence values. Therefore, this analysis has been identified as a TLAA requiring evaluation for the second period of extended operation.

An updated 80-year fracture mechanics evaluation was performed for the reflood thermal shock event to evaluate components with the limiting material properties from the PBAPS Units 2 and 3 RPV beltline plates, axial welds, and circumferential welds, which bounds the remainder. The analysis used projected 70 EFPY fluence values and determined that during the second period of extended operation, each RPV has sufficient toughness margin to prevent unacceptable flaw propagation due to thermal shock during reflooding after LOCA events.

The reactor pressure vessel reflood thermal shock analysis has been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.8 Core Shroud Reflood Thermal Shock Analysis

Neutron irradiation embrittlement may affect the ability of reactor vessel core shroud to withstand a low-pressure coolant injection thermal shock transient. The PBAPS reactor vessel core shrouds, which were fabricated from Type 304 stainless steel, have been analyzed for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of neutron irradiation exposure as documented in UFSAR Section 3.3.5.4. The core shrouds receive the maximum irradiation on the inside surface approximately opposite the midpoint of the fuel centerline. The maximum thermal shock stress in this region was determined to be 155,700 psi at the midpoint of the shroud, which is equivalent to 0.57 percent strain during the reflood thermal shock transient. This analysis has been identified as a TLAA requiring evaluation for the second of extended operation.

This issue was previously evaluated as a TLAA for the 60-year license renewal of the Brown's Ferry plants. Similar to PBAPS, the Brown's Ferry maximum thermal shock stress in the shroud was determined to be 155,700 psi with an equivalent 0.57 percent strain. In associated RAI responses, Browns Ferry provided material destructive testing results of highly irradiated Type 304 stainless steel to demonstrate that the core shrouds would withstand a low-pressure coolant injection event. These conclusions were accepted by the Staff. These same material destructive testing results can be used to disposition neutron irradiation embrittlement of the PBAPS core shrouds and their ability to withstand a low-pressure coolant injection thermal shock transient. For this TLAA, Brown's Ferry evaluated two material properties: "reduction in area" and "elongation".

For the "reduction in area" material property the Brown's Ferry evaluation concluded that a fluence value of 5.34E+21 n/cm^2 over the life of the core shroud results in sufficient ductility during the reflood thermal shock transient to resist the 155,700 psi stress. For the "elongation" material property the Brown's Ferry evaluation concluded that a fluence value of 8.0E+21 n/cm^2 over the life of the core shroud results in strain values, during the reflood thermal shock transient, which bound 0.57 percent strain. The maximum 80-year (70 EFPY) shroud weld fluence values for PBAPS Unit 2 is 3.63E+21 n/cm^2 and for Unit 3 is 3.45E+21 n/cm^2. Therefore, the conclusion for the Brown's Ferry core shrouds analysis also applies to the PBAPS core shrouds.

The projected 80-year (70 EFPY) shroud fluence values for PBAPS Units 2 and 3 are less than assumed fluence values established in the Brown's Ferry evaluation. Therefore, the conclusion for the Brown's Ferry shrouds also applies to the PBAPS shrouds and the analysis remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.9 Core Plate Rim Hold-Down Bolt Loss of Preload Analysis

The RPV core plate is attached to the core support structure by 34 stainless steel hold-down bolts arranged along the rim of the plate. These bolts are subject to stress relaxation (loss of preload) due to irradiation effects. An analysis was performed concluding that a reduction in preload as high as 19 percent over the 40-year life of the bolts is acceptable to meet design requirements. A subsequent reevaluation determined that this maximum relaxation value of 19 percent is applicable to an average fluence value of 8.0E+19 n/cm^2 over the entire length of the bolt located at the azimuthal location with peak fluence. These analyses were identified as TLAAs.

In order to determine if these analyses will remain valid for 80 years, RAMA fluence projections were prepared for 70 EFPY for the core plate rim hold-down bolts located at the azimuthal location with peak fluence. The bolts at the peak azimuthal location with the highest fluence for PBAPS Unit 2 and Unit 3 are bolt numbers 4, 15, 21, and 32, which have the same fluence values due to core symmetry. Fluence projections were made at the centerline of 27 discrete points equally spaced along the tensioned portion of these limiting bolts. For Unit 2, the 70 EFPY average fluence value of the limiting bolts is 6.57E+19 n/cm^2. For Unit 3, the 70 EFPY average fluence value of the limiting bolts is 6.53E+19 n/cm^2. Since these average fluence values are less than the 8.0E+19 n/cm^2 average fluence value previously evaluated in the TLAA, which resulted in an acceptable maximum relaxation value of 19 percent, the TLAA remains bounding for 70 EFPY and 80 years of operation. Therefore, the analysis remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.10 Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis

Jet pump slip joint repair clamps have been designed and installed on jet pumps in PBAPS Unit 2 to minimize slip joint vibration and wear of the jet pump assemblies. Eight clamps were installed in 2004, one was installed in 2008, and two were installed in 2014. None have been installed in Unit 3. The clamps apply a lateral preload to the slip joint, between the exit end of the inlet-mixer and the entrance end of the diffuser, to dampen jet pump vibration. The design analysis for the clamps evaluated a neutron fluence value of 1.115E+20 n/cm^2 for a 40-year design life of the clamp, and demonstrated that loss of preload resulting from neutron fluence during the design life of the clamps was acceptable. This analysis was identified as a TLAA.

In order to evaluate this TLAA, fluence at clamp locations inside the reactor vessel was determined from initial clamp installation in 2004 through the end of the second period of extended operation. The peak fluence value is projected to reach of 1.17E+19 n/cm^2 at the end of the second period of extended operation. Therefore, since this value is less than the design fluence value of 1.115E+20 n/cm^2, this TLAA has been determined to remain valid through the second period of extended operation. Therefore, the design analysis remains valid through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.11 Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis

The PBAPS jet pump (JP) assemblies have had auxiliary spring wedge assemblies installed to maintain lateral support for the jet pump inlet mixer. The design stress analysis considered potential aging effects, including loss of preload due to radiation effects based upon a design life of 40 years. The auxiliary spring wedge assemblies were installed in Unit 2 on JP 10, 12, and 18 in 2004, Installed on JP 14, 19, and 20 in 2006, replaced on JP 10 and JP 18 in 2014, and removed from JP 20 in 2014. Therefore, the earliest installed auxiliary spring wedge assembly will have a maximum in service time of approximately 49 years by the end of the second period of extended operation in August 2053.

An auxiliary spring wedge assembly was installed in Unit 3 on JP 14 in 2001 and will have a maximum in service time of approximately 53 years by the end of the second period of extended operation in July of 2054. Also, an auxiliary spring wedge assembly was installed in Unit 3 on JP 09 in 2001 and removed during the 2017 refueling outage.

The auxiliary spring wedge assembly design analysis determined that the fluence levels in the regions where the auxiliary wedges are installed on the jet pumps are less than 5.0E+20 n/cm^2 for a 40-year design life. An assumed 10 percent load relaxation was used in the analysis to account for loss of preload due to thermal and radiation effects. This analysis was identified as a TLAA.

In order to evaluate this TLAA, fluence projections were calculated for the limiting auxiliary spring wedge assembly for each unit. For Unit 2, the maximum fluence at the limiting auxiliary spring wedge assembly was determined to be 1.53E+20 n/cm^2 for the first installed auxiliary spring wedge assembly installed in 2004 to the end of the second period of extended operation. For Unit 3, the maximum fluence at the limiting auxiliary spring wedge assembly was determined to be 8.12E+18 n/cm^2 for the first installed auxiliary spring wedge assembly installed in 2001 to the end of the second period of extended operation. Each of these 70 EFPY fluence values are less than the 5.0E+20 n/cm^2 fluence value assumed in the design structural analysis for which the 10 percent loss of preload allowance was applied. Therefore, the design analysis remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.12 Jet Pump Riser Repair Clamp Loss of Preload Analysis

During the fall 1997 refueling outage for Unit 3, crack indications were detected in the heat-affected zones of the jet pump riser elbow-to-thermal sleeve welds for jet pump numbers 01/02 and 13/14. A mechanical clamping system designed to structurally replace these welds was installed in 1998. Since these clamshell-style clamps use bolts to maintain the proper clamping force, loss of preload due to neutron irradiation stress relaxation was a design consideration. The design specification assumed that the neutron fluence at the riser pipe clamp location would not exceed 2.5E+19 n/cm^2 for the service life of the clamps, until the end of the initial 40 years of operation. Since the neutron fluence value was based on the initial 40 years of operation, this analysis has been identified as a TLAA.

In order to determine if this fluence assumption will remain valid through 80 years of operation, neutron fluence was projected through the second period of extended operation. The 70 EFPY fluence value at the limiting Unit 3 jet pump riser clamp location was determined to be 5.29E+15 n/cm^2, which is less than the 2.5E+19 n/cm^2 fluence value assumed in the design specification for the clamp. Therefore, the design analysis remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.13 Replacement Core Plate Extended Life Plug Irradiation-Enhanced Stress Relaxation Analysis

The original design of the PBAPS Units 2 and 3 core plates included holes for bypass flow. It was discovered that the flow through the holes produced high velocity jets that impinged on the in-core instrument tubes, which subjected them to high levels of flow induced vibration, which led to wear on the adjacent fuel channels. The core plate holes were plugged to prevent the unwanted flow induced vibration. During the PBAPS Unit 3 fall 2001 refueling outage, all 129 reactor core plate plugs were replaced with extended life core support plugs. During the PBAPS Unit 2 spring 2012 refueling outage, all 129 reactor core plate plugs were replaced with extended life plugs. The extended life core support plugs have a service life of 35 EFPY corresponding to a fluence of 5.25E+20 n/cm^2. Due to the effects of irradiation-enhanced stress relaxation, the amount of force applied by the plug mandrel spring is dependent on the accumulated neutron fluence. The plug mandrel spring essentially holds the extended life core support plug tight in the core plate, against a force of 46.7 pounds created by the differential pressure in the core plate. Therefore, irradiation-enhanced stress relaxation of the mandrel spring due to neutron irradiation has been identified as a TLAA and was evaluated through the second period of extended operation.

Reevaluation of the service life of the extended life core support plugs concluded that the service life can be extended by an additional 20 EFPY for total service life of 55 EFPY. The reevaluation concluded that at the end of the 55 EFPY period the core support plug mandrel springs are estimated to experience fluence values of 8.25E+20 n/cm^2 with a resulting end of life mandrel spring preload of 111 pounds which exceeds the force acting on the plug due to the differential pressure, by margin of at least 100 percent. Therefore, the extended life core support plugs would not reach the end of their service life by 2067 for Unit 2 and 2056 for Unit 3, assuming an operating capacity of 100 percent. Since the second period of extended operation will end in 2053 for Unit 2 and 2054 for Unit 3, the evaluated service life of 55 years will not be exceeded during the second period of extended operation.

The analysis has been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.14 First License Renewal Application Core Shroud IASCC and Embrittlement Analysis

Section 4.3.2.2 of the first PBAPS License Renewal Application (LRA) presents a fluence threshold value of 5.0E+20 n/cm^2 beyond which IASCC and embrittlement may occur in BWR vessel internal components. Section 4.3.2.2 of the first PBAPS LRA concludes that the expected fluence on the inner surfaces of the core shroud would be 4.5E+20 n/cm^2 at the end of the 60-year first period of extended operation. Therefore, supplemental aging management of the core shroud to address IASCC and embrittlement is not required through the first period of extended operation. Since the core shroud analysis presented in Section 4.3.2.2 of the first PBAPS LRA determined that IASCC and embrittlement were not applicable aging effects expected to occur in 60 years, this analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

Fluence values for the PBAPS Unit 2 and Unit 3 core shroud are projected to exceed the threshold of 5.0E+20 n/cm^2 before the end of the second period of extended operation. Therefore, the core shroud will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the second period of extended operation in accordance with the BWR Vessel Internals (A.2.1.7) program.

The effects of aging on the intended function(s) of the reactor vessel core shroud will be adequately managed through the second period of extended operation by the BWR Vessel Internals (A.2.1.7) program, in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.15 Unit 3 Core Spray Replacement Piping Bolting Loss of Preload Evaluation

In 2013, portions of the Unit 3 Core Spray System piping segment located inside the reactor vessel were replaced from the thermal sleeves in reactor pressure vessel nozzles N5A and N5B to the shroud wall. A design report associated with this replacement evaluated loss of preload due to fluence on the most limiting bolting component. The loss of preload evaluation assumed a fluence value of 3.6E+19 n/cm^2 over a 40-year service life. This resulted in a reduction of preload to 3,775 pounds at the end of the 40-year period, which exceeds and meets the acceptance criterion of 3,504 pounds. Since the design report evaluated the effects of fluence on loss of preload over a 40-year service life, until 2053, the evaluation was identified as a TLAA that requires evaluation for the second period of extended operation, which ends in 2054 for PBAPS Unit 3.

The associated loss of preload evaluation was reevaluated by GEH for an additional five years of service life for a total of 45 years, until 2058. The reevaluation applied a fluence value of 4.1E+19 n/cm^2 which was assumed over 45 years. This resulted in a reduction of preload on the most limiting bolting component to 3,682 pounds through 2058, which exceeds and meets the acceptance criterion of 3,504 pounds. The Unit 3 replacement core spray piping bolting loss of preload evaluation has been satisfactorily projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3 Metal Fatigue Analyses

Metal fatigue was considered explicitly in the design process for pressure boundary components designed in accordance with ASME Section III, Class 1 requirements. Metal fatigue was evaluated implicitly for components designed in accordance with ASME Section III, Class 2 or 3 requirements or ANSI B31.1 requirements. Each of these fatigue analyses and evaluations are considered to be Time-Limited Aging Analyses (TLAAs) requiring evaluation for the second period of extended operation in accordance with 10 CFR 54.21(c) as described below.

A.4.3.1 Transient Cycle and Cumulative Usage Projections for 80 years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients usually described in design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. Since the existing fatigue analyses are based upon a number of transient cycles postulated to bound 60 years of service, projection of the transient cycles through the second period of extended operation is required to demonstrate that the analyses and waivers remain valid.

Projections of the transient cycles' through the second period of extended operations were developed for 80 years and used as input to calculate projected 80-year Cumulative Usage Factor (CUF) and Environmentally Assisted Cumulative Usage Factor (CUF_{en}) values to determine whether the existing analyses remain valid for 80 years. The number of transient cycles, CUF values, and CUF_{en} values have been projected through the second period of extended operation. The following fatigue TLAAs have been dispositioned using the projected number of transient cycles, CUF values, and CUF_{en} values through the second period of extended operation.

A.4.3.2 ASME Section III, Class 1 Fatigue Analyses

The PBAPS reactor pressure vessels (RPVs) were originally designed for 40 years of service in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Winter Addendum for Unit 2 and 3) for Class 1 design requirements. 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 design life of the plant in the design specifications. These Class 1 explicit 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. As stipulated in PBAPS's first License Renewal Application (LRA) the original 40-year RPV explicit fatigue analyses were updated with 60-year projected transient cycle numbers. The 60-year evaluations now serve as the current licensing basis (CLB), and have been identified as TLAAs for the second period of extended operation.

All PBAPS Class 1 piping systems were originally designed and evaluated in accordance with USAS (ANSI) B31.1 design requirements, which did not include explicit fatigue analysis. In the 1980s, PBAPS replaced reactor recirculation and the residual heat removal (RHR) system piping on both units. This replaced piping was designed in accordance with ASME Section III, 1980 Edition, including winter addenda through 1981, as Class 1 piping. In addition, the Unit 3, the flued-head penetrations for the RHR system were also analyzed for fatigue in accordance with ASME Section III, Class 1 requirements. Therefore, this replaced piping and flued-head penetrations were explicitly evaluated for fatigue. The remaining Unit 3 penetrations and all Unit 2 penetrations are designed in accordance with ASME Section III, Class 2 requirements, which do not include explicit fatigue analyses.

In the first PBAPS License Renewal Application all ASME Section III, Class 1 fatigue analyses were identified as TLAAs, evaluated for 60 years of operation, and dispositioned in accordance with 10 CFR 54.21(c)(iii) for management of the aging effect using the current Fatigue Monitoring program. These Class 1 explicit fatigue analyses have been identified as TLAAs that require evaluation for the second period of extended operation.

Eighty-year CUF and CUF_{en} projections show that all ASME Section III, Class 1 fatigue analysis will continue to meet the ASME Section III design limit of 1.0 through the second period of extended operation. To ensure the projected CUF and CUF_{en} values remain acceptable for the 80-year period of operation, the Fatigue Monitoring (A.3.1.1) program will monitor cumulative CUF and CUF_{en} for limiting locations though the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.3 ASME Section III, Class 1 Fatigue Waivers

The PBAPS reactor pressure vessels (RPVs) were originally designed for 40 years of service in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Winter Addendum) for Class 1 design requirements. The design stress reports for the Unit 2 and Unit 3 RPVs include fatigue waivers that determined that some RPV nozzles did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 were satisfied. The PBAPS RPV nozzles with fatigue waivers are the: Steam Outlet Nozzles, Liquid Control Nozzles, Instrumentation Nozzles, Vent Nozzles, Jet Pump Instrument Nozzles, and the RPV Drain Nozzles.

Since, the ASME Section III, Paragraph N-415.1 fatigue waiver criteria require postulated cycle input for the intended operating life of the plant, these fatigue waivers are TLAAs. Therefore, fatigue waiver evaluations were reevaluated for the second period of extended operation using the 80-year projected number of transients. The results of the reevaluation show that the criteria in ASME Section III, Paragraph N-415-1 remain satisfied through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3.4 ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses

Piping designed in accordance with ASME Section III, Class 2 or 3, or ANSI B31.1 Piping Code design rules is not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in the design process. If the numbers of anticipated thermal cycles exceed specified limits, these codes require the application of a stress range reduction factor to the allowable stress to prevent damage from cyclic loading. This is an implicit fatigue analysis since it is based upon the anticipated number of cycles for the life of the piping system.

These codes first require the overall number of thermal and pressure cycles expected during the plant lifetime of these components to be determined. A stress range reduction factor is then determined for that number of cycles using the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor of 1.0 is applied, which would not reduce the allowable stress values. For higher numbers of cycles, the stress range reduction factors limit the allowable stresses that can be applied to the piping.

Portions of the following Class 2 and 3 and ANSI B31.1 piping systems within the scope of license renewal are directly connected to Reactor Coolant System (RCS) and are affected by the same operational transients that result in thermal cycles for the attached Class 1 RCS piping: Control Rod Drive, Core Spray, Feedwater, Main Steam, Offgas and Recombiner, Primary Containment Isolation, Reactor Recirculation, Reactor Vessel Instrumentation, Residual Heat Removal, and Standby Liquid Control Systems. These transient cycles have been projected for 80 years. The projections demonstrate that the total number of thermal cycles for these piping systems will not exceed 50 percent of the 7,000-cycle threshold that would result in a reduction in the stress range reduction factor. Therefore, these TLAAs have been demonstrated to remain valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

For the remaining Class 2 and 3 and ANSI B31.1 piping systems within the scope of license renewal that are affected by thermal and pressure transients that are different than the RCS transients, an operational review was performed. These piping systems include portions of the Auxiliary Steam, Emergency Diesel Generator, Fire Protection, High Pressure Coolant Injection, Process Sampling, Reactor Core Isolation Cooling, and Reactor Water Cleanup Systems.

The review concluded that the total number of thermal cycles for these systems, projected through the period of extended operation, will not exceed 68 percent of the 7,000-cycle threshold. Therefore, the stress range reduction factors originally selected for the Class 2 and 3 and ANSI B31.1 piping systems remain applicable and these TLAAs have been demonstrated to remain valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.5 Environmental Fatigue Analyses for RPV and Class 1 Piping

NUREG-2191, Revision 0 provides a recommendation for evaluating the effects of the reactor water environment on the fatigue life of a set of sample reactor coolant system components. One method to satisfy this recommendation is to assess the impact of the reactor coolant environment on a sample of critical components as described in NUREG/CR-6260. Additional component locations are evaluated if they are considered to be more limiting than those considered in NUREG/CR-6260.

Environmental fatigue calculations were performed for component locations listed in NUREG/CR-6260 for the older-vintage BWR. In order to ensure that any other locations that may not be bounded by the NUREG/CR-6260 locations were evaluated, environmental fatigue screening calculations were performed for all Class 1 RPV and piping component locations that have a reported CUF value in the governing stress reports and are exposed to the reactor coolant. These environmental fatigue calculations were performed for the limiting wetted locations for each material type in each thermal zone.

These environmental fatigue analyses will be managed by the Fatigue Monitoring (A.3.1.1) program in the same manner as the ASME Section III, Class 1 fatigue analyses. The program ensures that the Environmental Assisted Cumulative Usage Factors (CUF_{en}) are maintained below the design limit of 1.0. If a CUF_{en} limit is approached, corrective actions are triggered to prevent exceeding the limit.

The effects of aging on the intended functions will be adequately managed by the Fatigue Monitoring (A.3.1.1) program through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6 Reactor Vessel Internals Fatigue Analyses

The PBAPS reactor vessel internals were not designed in accordance with ASME Section III. However, some of the reactor vessel internals have been subsequently evaluated for fatigue using methods from ASME Section III. These evaluations are described in following subsections:

A.4.3.6.1 Generic BWR Fatigue Analyses for Various Reactor Vessel Internal Components

The PBAPS Extended Power Uprate (EPU) license amendment submittal to the NRC in 2012 and the Measurement Uncertainty Recapture (MUR) Power Uprate license amendment submittal to the NRC in 2017 documented generic BWR fleet 40-year and 60-year CUF values for various reactor vessel internal components. This included the shroud, the core plate, the top guide, the jet pump (riser brace), the core spray line (in-vessel), the core spray sparger, and the feedwater sparger. These generic CUF values were calculated by GEH for the BWR fleet and are bounding for PBAPS. The various generic CUF values were used in the submittals to demonstrate that PBAPS reactor vessel internal components are structurally qualified for operation in the EPU and MUR operating conditions for a 60-year plant life.

The generic 40-year design CUF values were calculated by GEH in BWR fleet fatigue analyses, which assumed various normal, upset, emergency, or faulted transient severities and numbers of transient cycles. Generic 60-year CUF values were calculated by multiplying the generic 40-year design CUF values by 1.5.

These generic analyses have been identified as TLAAs and have been reevaluated for the second period of extended operation. Eighty-year CUF values have been determined for the core plate, the top guide, the jet pump (riser brace), the core spray line (in-vessel), the core spray sparger, and the feedwater sparger. All of these 80-year CUF values are projected to remain less than the acceptance criterion of 1.0 through the second period of extended operation. Section A.4.3.6.2 addresses the “Shroud” component.

These various PBAPS reactor vessel internal generic fatigue analyses have been successfully projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3.6.2 Generic BWR Fatigue Analyses for the Core Shroud

The PBAPS Extended Power Uprate (EPU) license amendment submittal to the NRC in 2012 and the Measurement Uncertainty Recapture (MUR) Power Uprate license amendment submittal to the NRC in 2017 documented generic 40-year and 60-year CUF values of 0.593 and 0.89 respectively for the reactor vessel core shroud. The generic 40-year CUF value was generated by GEH in a generic BWR fleet fatigue analysis. The generic 60-year CUF value was calculated by GEH by multiplying the original 40-year design CUF values by 1.5. Since this generic CUF fatigue analysis was used to demonstrate that the PBAPS core shrouds are structurally qualified for operation in the EPU and MUR operating conditions for a 60-year plant life it was identified as TLAA and reevaluated for the second period of extended operation.

The original 40-year GEH generic fatigue evaluation, which was intended to bound all BWR/4 and BWR/5 plant shrouds, used a worst-case approach to define generic the reactor vessel geometry, and thermal and mechanical stresses. The original 40-year GEH generic fatigue analysis assumed:

- 15 cycles of Cooldown - Loss of AC Power Natural Circulation Restart;
- 10 cycles of Cooldown - LPCI During Vessel Startup & Shutdown; and
- 10 cycles of Operational Basis Earthquake (OBE).

For a 60-year plant life the above assumed number of transient cycles was increased by a factor 1.5.

As of May 2017, PBAPS Units 2 and 3 have not experienced any of these transient cycles, therefore it is not credible that either PBAPS unit will experience these numbers of cycles over the remaining 80-year operating period. Therefore, the 60-year generic CUF value of 0.89 is conservative for 80 years of operation for both PBAPS units and the generic fatigue analysis remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.6.3 Core Shroud Support Fatigue Analysis Reevaluation

As discussed in the first PBAPS License Renewal Application, the core shroud support fatigue analysis was reevaluated in 1998 for the effects of increased recirculation pump starts with the recirculation loops outside of their thermal limits specifically for PBAPS. This reevaluation has been identified as a TLAA that requires evaluation for the second period of extended operation.

The SI:FatiguePro™ software includes two bounding locations representing low alloy steel and nickel alloy materials in the “Shroud Support, Baffle Plate to Vessel Junction”. These locations are bounding with respect to the cumulative fatigue usage associated with the “Core Shroud Support Fatigue Analysis Reevaluation” TLAA. The Fatigue Monitoring (A.3.1.1) program will monitor CUF_{en} for these bounding locations and ensure corrective action is taken prior to exceeding the acceptance criterion of 1.0 through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6.4 Jet Pump Diffuser/Core Shroud Support Plate Fatigue Analysis

The first PBAPS License Renewal Application projected that the 60-year CUF value for the “Jet Pump Diffuser/Core Shroud Support Plate” would not exceed a value of 0.525. This analysis has been identified as a TLAA that requires evaluation for the second period of extended operation.

The SI:FatiguePro™ software includes a bounding location for the “Jet Pump Shroud Support, Diffuser Weld to Baffle Plate”. This location is bounding with respect to the cumulative fatigue usage associated with the “Jet Pump Diffuser/Core Shroud Support Plate” fatigue analysis TLAA. The Fatigue Monitoring (A.3.1.1) program will monitor CUF_{en} for this bounding location and ensure corrective action is taken prior to exceeding the acceptance criterion of 1.0 through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6.5 Replacement Steam Dryer Stress Report and Fatigue Evaluation

To support the Extended Power Uprate (EPU) project, both PBAPS Units 2 and 3 replaced the reactor pressure vessel steam dryers. The new steam dryers were evaluated in 2014 in accordance with the requirements of ASME Section IIII, Division I, Subsection NG, “Core Support Structure”, 2007 Edition with 2008 Addenda. This evaluation has been identified as a TLAA that requires evaluation for the second period of extended operation.

The fatigue evaluation assumed 400 startup and shutdown transient cycles and 1 OBE event commencing in 2014. The 80-year transient projections show that the total number of startup and shutdown transient cycles will not exceed the 400 assumed in the fatigue evaluation for either unit over the entire 80-year life of each unit.

Therefore, the replacement steam dryer fatigue evaluation remains valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.7 High-Energy Line Break (HELB) Analyses Based on Cumulative Fatigue Usage

High-Energy Line Break (HELB) analyses for PBAPS used the CUF values from the ASME Class 1 fatigue analyses as input in determining intermediate break locations. Locations with a design CUF value less than or equal to 0.1 did not require an intermediate break to be postulated. Since the HELB analyses are based on the Class 1 piping fatigue TLAAs that provided the CUF values, the HELB analyses have been identified as TLAAs.

The current Fatigue Monitoring program uses SI:FatiguePro™ 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. SI:FatiguePro™ monitors the bounding location for all High-Energy Line Break analyses.

The Fatigue Monitoring (A.3.1.1) program will be enhanced to add a HELB CUF acceptance criterion of 0.1 for this bounding location. The Fatigue Monitoring program administrative requirements will ensure that corrective action is taken prior to the bounding location CUF value exceeding the HELB break exclusion acceptance criterion of 0.1. Therefore, these fatigue analyses will be managed by the Fatigue Monitoring (A.3.1.1) program through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.8 Inservice 60-Year RPV Closure Head Weld Flaw Analyses

Volumetric examinations identified flaws on the Unit 3 closure head meridional welds CH-MA, CH-MC, and CH-MF in 2001; on the Unit 2 closure head meridional weld CH-MB in 2002; and on the Unit 2 closure head to flange weld CH-C-2 in 2010. Prior to the examinations, review of the fabrication and inspection history of these welds revealed that the indications had existed since fabrication, had previously been identified in prior ISI examinations, and most likely some of the indications would be rejected when reexamined under the new Performance Demonstration Initiative (PDI).

Three separate flaw evaluations were performed using fatigue crack growth evaluations in accordance with ASME Section XI Subsection IWB-3600 and Appendix A. The flaw evaluations assumed: 1) 100 “Bolt-Up” transient cycles, 2) 195 “Hydrostatic Test” transient cycles, and 3) 245 “Heatup-Cooldown” transient cycles and concluded that the limiting flaws were acceptable even after accounting for projected crack growth for the life of the plant including license renewal (60 total years). Therefore, these flaw evaluations have been identified as TLAAs.

The 80-year transient cycle projections show that the total number of: “Bolt-Up”, “Hydrostatic Test”, and “Heatup-Cooldown” transient cycles will not exceed the number of transient cycles assumed in the flaw evaluations. Therefore, the three flaw evaluations remain valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.4 Environmental Qualification of Electric Equipment

A.4.4.1 Environmental Qualification of Electric Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs) for PBAPS. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The Environmental Qualification of Electric Components (A.3.1.3) program will manage the effects of aging effects for the components associated with the environmental qualification through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. Reanalysis of an aging evaluation to extend the qualifications of components is performed on a routine basis as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, ongoing qualification, and corrective actions if acceptance criteria are not met.

If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful.

The effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The Environmental Qualification of Electric Components (A.3.1.3) program has been demonstrated to be capable of programmatically managing the qualified lives of the electrical components falling within the scope of the program for second license renewal in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.5 Concrete Containment Tendon Prestress Analysis

A.4.5.1 Concrete Containment Tendon Prestress Analysis

The PBAPS containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

A.4.6 Primary Containment Fatigue Analyses

A.4.6.1 Primary Containment Structures, Penetrations, and Associated Components with Fatigue Analyses

The original design for the Primary Containment for both units was in accordance with ASME Section III, Subsection B, 1965 Edition with addenda through the Summer of 1966, which did not require an evaluation of fatigue. Subsequent to the original design, elements of the PBAPS containment were reanalyzed in response to discoveries by General Electric (GE) and others of unevaluated loads due to design basis events and Safety Relief Valve (SRV) discharge. The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge, design basis loss of coolant accident (LOCA) events, and OBE and SSE events. Components of the Primary Containment that were analyzed included the torus shell, the torus penetrations, the drywell-to-torus vents, SRV discharge piping, attached piping to the torus, and the drywell to torus vent bellows. These analyses have been identified TLAAs.

In 1997 and 1998 PBAPS Units 2 and 3 replaced the RHR and Core Spray System suction strainers in the torus. These new suction strainers and their supports were designed to ASME Section III Subsections NC, NE, and NF

1980 edition up to and including Winter 1981 Addenda and were therefore evaluated for fatigue. The suction strainer and support evaluations used as the same transient cycle inputs as the above containment analyses. Therefore, the suction strainer and support analyses have been identified TLAAs.

The Fatigue Monitoring (A.3.1.1) program uses SI:FatiguePro™ to monitor fatigue of these components and is credited with managing these TLAAs. The following SI:FatiguePro™ locations bound the above components for both Units 2 and 3: "Torus Penetrations (CS)/ Torus Shell" and "Torus (CS)/Torus Shell."

The effects of aging on the intended function of these components will be adequately managed by the Fatigue Monitoring (A.3.1.1) program through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.2 Containment Process Line Penetration Bellows

The original PBAPS Units 2 and 3 main steam line, feedwater line, HPCI steam line, RHR supply and return line, RWCU pump suction line, core spray discharge line, and vessel head spray process line containment penetration bellows were designed to ASME Section III, 1968, Appendix IX-200, Class B Vessels and Codes Cases 1177-5 and 1330-1. The design specification for the original bellows specified 200 startup-shutdown transient cycles and a minimum of 1,500 "normal operating cycles" that would encompass Design Basis Accident (DBA) transient cycles. The Unit 3 RHR system penetration bellows were replaced in 1988 and 1989 and were designed to ASME Section III, 1980 Edition with Winter 1981 Addenda, Section NC-3649.4. The design specification for these replacement penetration bellows specified 1,500 DBA transient cycles. These analyses have been identified TLAAs.

Transient cycle projections were performed that determined that the specified transient cycles limits will not be exceeded in 80 years. The analyses remain valid through the second period of extended operations in accordance with 10 CFR 54.21 (c)(1)(i).

A.4.7 Other Plant-Specific Time-Limited Aging Analyses

A.4.7.1 Cranes Cyclic Loading Analyses

The cranes listed below are within the scope of second license renewal and their design meets the intent of Crane Manufacturers Association of America (CMAA) Specification 70, which includes considerations for frequency of operation and expected load sizes relative to their maximum load capacity. Specification CMAA 70 allows between 20,000 and 100,000 load cycles over the service life of each crane. Therefore, 20,000 load cycles is a conservative limitation on the number of load cycles for each of these cranes. Based on these considerations, cranes are designed for a given service class classification with an expected maximum number of design load cycles over their life of the crane. The expected maximum number of design load cycles over the life of each crane provides the basis for the TLAA evaluation.

Reactor Building Cranes

Each PBAPS unit has a reactor building crane that is within the scope of license renewal. The number of anticipated lifts for each of these cranes is estimated to be 4,032 cycles through the second period of extended operation; which is approximately 20 percent of the conservative limitation.

Emergency Diesel Generator Bridge Cranes

Each of the four Emergency Diesel Generator rooms has a bridge crane that is within the scope of license renewal. The number of anticipated lifts for each of these cranes is estimated to be 4,500 cycles through the second period of extended operation; which is approximately 25 percent of the conservative limitation.

Turbine Building Cranes

Each PBAPS unit has a turbine building crane that is within the scope of license renewal. The number of anticipated lifts for each of these cranes is estimated to be 7,340 cycles through the second period of extended operation; which is approximately 40 percent of the conservative limitation.

Circulating Water Pump Structure Crane

PBAPS has a common circulating water pump structure crane that is within the scope of license renewal. The number of anticipated lifts for this crane is estimated to be 1,780 cycles through the second period of extended operation; which is approximately 10 percent of the conservative limitation.

These analyses remain valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.2 Reactor Vessel Main Steam Nozzle Clad Removal Corrosion Allowance

A 1974 analysis, developed to justify removal of the PBAPS Units 2 and 3 reactor vessel main steam nozzle cladding, used a time-dependent corrosion rate over 40 years and a corrosion allowance as acceptance criteria. As such, the evaluation was identified as a TLAA in the first License Renewal Application (LRA) that must be reevaluated for the second period of extended operation.

The evaluation concluded that a total general wall loss of 0.065 inches is an acceptable corrosion allowance for the reactor vessel main steam nozzles. Section 4.7.1 of PBAPS's first LRA documented that internal surfaces the reactor vessel main steam nozzles will only experience general wall loss of 0.030 inches over a 60-year period, which is significantly less than the corrosion allowance acceptance criterion of 0.065 inches. Based on the same corrosion rate the 80-year total general wall loss is projected to be 0.040 inches and significantly less than the corrosion allowance acceptance criterion of 0.065 inches.

The corrosion allowance analysis has been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.7.3 Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking

NUREG-0619 was issued by the NRC per Generic Letter (GL) 81-11 in February 1981 because of observed cracking on the inside surfaces of BWR feedwater nozzles at the blend radius and bore. One of the causes of the cracking was determined to be leakage between the feedwater nozzle and the thermal sleeve which resulted in rapid thermal cycling, on the order of a few cycles per second. Such cracking was observed in the feedwater nozzles at PBAPS Units 2 and 3 early in each unit's life before 1980. The cracks initiated by this rapid thermal cycling fatigue mechanism were small shallow internal cracks. However, these small cracks could potentially propagate to larger cracks by low cycle fatigue due to normal plant transients such as heatup, cooldown, and feedwater transient cycles.

In 1980 and 1981, the following three modifications recommended within NUREG-0619 were implemented on PBAPS Units 2 and 3 to reduce or eliminate the feedwater nozzle rapid thermal cycling fatigue cracking mechanism: (a) installation of improved nozzle triple thermal sleeves with dual piston ring seals, (b) removal of cladding from the nozzle bore and blend radii, and (c) improvement of the low-flow feedwater controllers. Also, the control rod drive return line (CRDRL) nozzles have been capped to eliminate cracking due to rapid thermal cycling. The CRDRL nozzles are inspected in accordance with the ASME Code, Section XI, Subsection IWB, Tables IWB-2500. The CRDRL nozzle-to-cap weld examinations are performed at a frequency specified by the BWR Stress Corrosion Cracking (A.2.1.5) program that implements commitments from NRC Generic Letter 88-01 and BWRVIP-75-A. The implementation of the modifications and improvements to plant operations at low flow conditions in the early 1980's were effective in preventing additional rapid thermal cycle fatigue cracking in the PBAPS Units 2 and 3 feedwater nozzles.

In 1983, augmented ISI inspections of the feedwater nozzles were implemented on PBAPS Units 2 and 3 based on the recommendations in NUREG-0619. The inspections depended on a fracture mechanics analyses that were used to determine inspection criteria and intervals. In 1998, PBAPS performed a new plant-specific fracture mechanics analysis in accordance with the BWROG and NRC approved guidance which was accepted by the NRC as an acceptable alternative to NUREG-0619. Since this issue was identified as a TLAA for the first license renewal, it has been reevaluated for the second period of extended operation.

The first PBAPS LRA credited "Augmented Inspections" in accordance with the Inservice Inspection (ISI) Program for the management of rapid thermal cycling fatigue cracking in feedwater nozzles. The inspections would, in effect, provide confirmation that cracking due to rapid thermal cycling fatigue or low cycle fatigue is not occurring. In addition, the first PBAPS LRA credited the Fatigue

Management Activities Program for aging management of low cycle fatigue in the feedwater nozzles. This approach was evaluated by the NRC in NUREG-1769 and was found acceptable.

However, UFSAR Appendix C, Section C.5.3.1.1 documents that the feedwater nozzles have been evaluated for low cycle fatigue in accordance with ASME Section III as Class 1 components through the first period of extended operation. While the PBAPS plant-specific fracture mechanics analysis for rapid cycle thermal fatigue is not a TLAA and is no longer used as the basis for inspection frequency, the ASME Section III fatigue analysis of the feedwater nozzles is considered a TLAA and must be evaluated for the second period of extended operation.

Augmented Inspections in accordance with the PBAPS ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program is credited for the management of rapid thermal cycling fatigue cracking in feedwater nozzles. These inspections provide confirmation that cracking due to rapid thermal cycling fatigue or low cycle fatigue is not occurring through the second period of extended operation. Therefore, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program is credited for managing rapid thermal cycling fatigue through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

In addition, the Fatigue Monitoring (A.3.1.1) program currently uses SI:FatiguePro™ to monitor low cycle fatigue of feedwater nozzles by computing the CUF_{en} values based upon the cumulative numbers of fatigue transient cycles. The SI:FatiguePro™ locations “Feedwater Nozzles (LAS)/Beyond Second Piston Ring” and “Feedwater Nozzles (CS)/Safe End Between First and Second Piston” will monitor fatigue for the feedwater nozzles to ensure that EAF usage factors will remain less than 1.0 through the second period of extended operation. Therefore, the Fatigue Monitoring (A.3.1.1) program is credited with managing the feedwater nozzle low cycle fatigue through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.4 Fracture Mechanics analysis of ISI-Reportable Indications for Group I Piping: As-forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT

A preservice ultrasonic volumetric examination (UT) discovered an imbedded as-forged laminar indication in an elbow on a PBAPS Unit 3 main steam line. The indication did not extend into a weld. Although this portion of the main steam system piping is not subject to an ASME III Class 1 fatigue analysis, a stress and a 40-year-life fatigue analysis was performed. The analysis concluded that the primary, secondary, and primary plus secondary stresses and cumulative usage factors met ASME III requirements. As such, the evaluation was determined to be a TLAA in the first License Renewal Application which was reevaluated for the second period of extended operation.

The original analysis calculated a 40-year worst case cumulative usage factor (CUF) of 0.036; assuming the laminar indication extends into the weld. A CUF of value 1.0 is considered the approximate threshold at which a fatigue crack may initiate and propagate. The first PBAPS LRA projected this to a maximum CUF of 0.054 for 60 years. In the SER for PBAPS's first LRA (NUREG-1769) the staff concluded that: "By reporting that the CUF is considerably below the design limit of 1.0, the staff concludes that the applicant has provided reasonable assurance that the flaw will not propagate during the 40-year life of the plant and the period of extended operation." Therefore, over an 80-year period the maximum CUF is projected to be 0.072 which is less than the ASME Section III cumulative fatigue acceptance criterion of 1.0.

The fatigue analysis has been projected through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.7.5 Unit 3 Core Spray Replacement Piping Fatigue and Leakage Assessment

In 2013, portions of the Unit 3 Core Spray System piping segment located in the reactor vessel, from the N5A and N5B nozzle thermal sleeves to the shroud wall were replaced. Some of the mechanical replacement hardware introduced a number of very small openings in the new piping segment and its attachment to the shroud wall, thus providing leakage paths. Therefore, a leakage assessment was performed to demonstrate that the new piping would perform its intended function through the remaining life of the unit. The leakage assessment assumed corrosion rates over 40 years. The 40-year service life of the Core Spray System piping segment ends in 2053, and the second period of extended operation will end in 2054 for Unit 3.

In addition, a fatigue analysis of the new piping system and associated bolting concluded a maximum design CUF value of 0.0565. The fatigue analysis assumed the following transients starting in 2013: 161 cycles of Startup and Shutdown; 197 cycles of Scram: Turbine Trip and All Other Scrams; 80 cycles of Loss of Feedwater; 40 cycles of Scram – Single Relief or Safety Valve Blowdown; 50 Cycles of Injections; and one OBE with 50 cycles.

Since the leakage assessment and fatigue analysis assumed a 40-year service life they have been identified as TLAAs.

The leakage assessment was reevaluated for an additional five years for a total of 45 years, until 2058. The reevaluation determined that the conclusions of the original leakage assessment are valid for an additional five years.

The associated fatigue analysis was also reevaluated for an additional five years of service life for a total of 45 years, until 2058. The reevaluation concluded that the originally assumed number of transient cycles, shown above; remain valid for 45 years and the design CUF value of 0.0565 remains unchanged.

Therefore, both the leakage assessment and the fatigue analysis remain valid through the second period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.5.0 Second License Renewal Commitment List

A.5 Second License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing program is credited.	Ongoing	Section A.2.1.1
2	Water Chemistry	Existing program is credited.	Ongoing	Section A.2.1.2
3	Reactor Head Closure Stud Bolting	Existing program is credited.	Ongoing	Section A.2.1.3
4	BWR Vessel ID Attachment Welds	Existing program is credited.	Ongoing	Section A.2.1.4
5	BWR Stress Corrosion Cracking	Existing program is credited.	Ongoing	Section A.2.1.5
6	BWR Penetrations	Existing program is credited.	Ongoing	Section A.2.1.6
7	BWR Vessel Internals	BWR Vessel Internals is an existing program that will be enhanced to: 1. Install core plate wedges no later than six months prior to the second period of extended operation, or before the end of the last refueling outage prior to the second period of extended operation, whichever occurs later; or, submit an inspection plan for the core plate rim hold-down bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation. 2. Perform a VT-3 inspection of the jet pump inlet mixer and beam regions every refuel cycle after a fluence value of 1.3E+20 n/cm^2 (51 EFPY for Unit 2 and 63 EFPY for Unit 3) is reached at the jet pump holddown beam. 3. Perform periodic visual inspections of the PBAPS Westinghouse (Nordic style) stainless steel steam dryers for the aging effects of loss of material	Program will be enhanced in accordance with the schedule described within the commitments. Initial steam dryer inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.7

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		and cracking at a frequency not exceeding 10 years, with the first inspections performed prior to the second period of extended operation, as described below. The inspection guidance contained in BWRVIP-139-A does not address the Westinghouse (Nordic style) steam dryers installed in PBAPS Unit 2 and Unit 3 and therefore is not directly applicable. However, the general principles and conclusions from BWRVIP-139-A, "BWR Vessel and Internals Project: Steam Dryer Inspection and Flaw Evaluation Guidelines", BWRVIP-181-R1-A, "BWR Vessel and Internals Project: Steam Dryer Repair Design Criteria", and Regulatory Guide 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing" were applied to the inspection plan described in WCAP-17635-P, "Peach Bottom Atomic Power Station Unit 2 and Unit 3 Replacement Steam Dryer Comprehensive Vibration Assessment Program (CVAP)". WCAP-17635-P also includes manufacturer's recommendations based on relevant operating experience. The scope of the inspection will include the items listed in Table 1 below. The steam dryer inspections are based on the BWRVIP-139-A and WCAP-17635-P guidelines to identify loss of material (wear) and cracking using appropriate visual examination techniques (e.g., VT-1, VT-3) and qualified inspectors. The examination procedures identify the type and location of examination required for each dryer component as well as the reason for inspection. Acceptance criteria are consistent with BWRVIP-139-A and are described in procedures and work instructions. Flaws and abnormal indications identified will be entered into the corrective action program for engineering evaluation. The evaluations will consider increasing inspection frequency and scope as appropriate. Identified degradation left in the as found condition will be reinspected as required by the engineering evaluation. The repair design criteria contained in BWRVIP-181-R1-A and BWRVIP-139-A will be used for any future repairs of the steam dryers. Repairs to the steam dryer will be inspected as specified in the repair design package.		

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Table 1 Steam Dryer Inspection Program for the Second Period of Extended Operation in accordance with WCAP-17635-P		

Inspection Location	Basis for Selection
1. Overall General Inspection of Outside of the Replacement Steam Dryer (to include outside of skirt)	Industry Operating Experience (BWRVIP-139-A, Section 1.1, Section 2.4.2) General Inspection for evidence of damage
2. Lifting Rods Top Ends (Unit 3 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
3. Hold Down Rods Top Ends (Unit 2 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
4. Support Ring Bottom Surface	RG 1.20 Sec 2.3 (1)(b,d) Surfaces in contact during operation
5. Outer hood (welds on outer surface)	Industry Operating Experience (BWRVIP-139-A, Section 1.1, Section 2.4.2) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)
6. Outer Ring Top Cage	Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		<table><tr><td>7. Weld attachments between the brackets to the lifting rod and hold down rod and weld attachments between the brackets to top plate (lifting rod, Unit 3 only)</td><td>Industry Operating Experience (BWRVIP-139-A, Section 2.4.8) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)</td></tr></table>		
8	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide assurance that reactor coolant pressure boundary CASS components (i.e., Class 1 piping and pump casings) with the potential for significant thermal aging embrittlement meet their intended functions.	Program will be implemented no later than six months prior to the second period of extended operation.	Section A.2.1.8
9	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion is an existing program that will be enhanced to: 1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for the second period of extended operation.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.9
10	Bolting Integrity	Bolting Integrity is an existing program that will be enhanced to: 1. Ensure that submerged carbon steel closure bolts on the ESW, HPSW, and fire protection pumps are inspected for loss of material and to confirm that the closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of closure bolting on these pumps during pump overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation. 2. Ensure that submerged stainless steel mechanical bolts on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.10

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		traveling screens are inspected for loss of material and to confirm that the mechanical bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of mechanical bolting on these screens during overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation. 3. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for cracking and loss of material for the carbon steel/ air-indoor uncontrolled and the stainless steel/ air-indoor uncontrolled material and environment combinations. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Opportunistic inspections during maintenance activities may be credited during the same 10-year period. 4. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for loss of material for the carbon steel/ air-outdoor material and environment combination. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 25 bolt inspections shall be performed each 10-year period during the second period of extended operation for both Units 2 and 3. Opportunistic inspections during maintenance activities may be credited during the same 10-year period. 5. Revise site walkdown procedures to specify proper lighting and appropriate distances to adequately identify visible component leakage, evidence of past leakage, or other age-related degradation on pressure-retaining bolted joints that contain fluids such as water, oil, or steam. Cameras and video equipment may be used to supplement these inspections.		

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		6. Revise existing repetitive tasks to provide guidance for proper lighting and appropriate inspection distances to adequately identify loss of material in submerged environments. Cameras and video equipment may be used to supplement these inspections. 7. Ensure no fewer than five additional bolts are inspected for each sample based inspection that does not meet acceptance criteria, or 20 percent of the total bolt population of each applicable material, environment, and aging effect combination; whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis are performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval for which the original sample based inspections are conducted.		
11	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System is an existing program that will be enhanced to: 1. Provide procedural direction to perform additional inspections if the cause of the aging effect for each applicable material and environment combination is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. These additional inspections will be conducted if any of the inspections do not meet acceptance criteria. No fewer than five additional inspections will be performed for each inspection that does not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.11
12	Closed Treated Water Systems	Closed Treated Water Systems is an existing program that will be enhanced to: 1. Perform condition monitoring including opportunistic visual inspections and sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the second period of extended operation. The rate of identified degradation will be projected until the next scheduled inspection. Additional sample-based inspections will be performed if aging effects are identified. If those inspections identify aging effects, the corrective action program will be used to	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.12

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		determine the extent of condition and extent of cause to determine the further extent of inspections.		
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to: 1. Provide additional guidance to include inspection of crane-related bridges, structural members, and structural components for deformation, cracking, and loss of material due to corrosion or wear; and associated bolted connections for loss of material, cracking, and indications of loss of preload. 2. Provide procedural direction to document deficiencies identified during inspection activities within the corrective action program. 3. Provide site-specific procedural direction to evaluate and repair visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.13
14	Compressed Air Monitoring	Compressed Air Monitoring is an existing program that will be enhanced to: 1. Perform daily inspection of instrument nitrogen after dryer desiccant for signs of moisture. Results will be recorded and reviewed to determine if corrective actions are required. 2. Perform opportunistic visual inspections of component internal surfaces exposed to a dry air environment for signs of loss of material due to corrosion.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.14
15	BWR Reactor Water Cleanup System	Existing program is credited.	Ongoing	Section A.2.1.15
16	Fire Protection	Fire Protection is an existing program that will be enhanced to: 1. Perform periodic visual inspection every 18 months for identification of corrosion that may lead to loss of material on the external surfaces of the low pressure carbon dioxide fire suppression systems. 2. Perform periodic visual inspection of combustible liquid spill retaining curbs every 24 months.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.16

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
17	Fire Water System	Fire Water System is an existing program that will be enhanced to: 1. Revise flow test procedures to include: a. Inspector test flush acceptance criteria for wet pipe sprinkler systems that currently do not include the requirement to record time to flow from the opened test valve. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10 percent reduction in full flow pressure when compared to previously performed tests. An issue report shall be generated in the corrective action program to determine the cause and corrective actions. c. If acceptance criteria are not met, at least two additional tests shall be performed. If acceptance criteria are not met during follow-up testing, the test shall be performed on the same system, on the other unit. 2. Perform air flow tests on the hydrogen seal oil and reactor building water curtains every two years to ensure deluge piping and nozzles are unobstructed and there are no flow blockages. 3. Increase the frequency of air flow tests through the standby gas treatment and recombiner system deluge piping and nozzles to every two years to ensure piping and nozzles are unobstructed and there are no flow blockages. 4. Revise procedures to improve guidance for external visual inspections of the in scope sprinkler systems piping and sprinklers at least every two years to inspect for excessive corrosion, loss of material, leaks, and proper sprinkler orientation. Corroded, leaking or damaged sprinklers shall be replaced. 5. Perform external visual inspections of the in scope above ground fire main piping every two years to identify excessive corrosion, loss of material, leaks, and physical damage. 6. Perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric wall thickness examinations will be performed if	Program will be enhanced no later than six months prior to the second period of extended operation. Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.17

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the corrective action program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25 Appendix D.5, Flushing Procedures. The internal visual inspections will consist of the following: a. Wet pipe sprinkler systems - 50 percent of the wet pipe sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - Yard transformer deluge systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 7. Perform a one-time volumetric wall thickness inspection, prior to the second period of extended operation, on a sample of the original yard transformer deluge system supply piping that was not replaced during transformer replacements and is periodically subjected to flow during functional testing. 8. Revise service water bay inspection procedures to include inspection of the motor driven fire pump intake strainer. 9. Perform flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five-year frequency to demonstrate the capability to provide the design pressure at required flow.		

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033   Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		10. Flush deluge system mainline supply basket strainers until clear, following functional testing of yard deluge systems. 11. Perform a one-time inspection of the auxiliary boiler fuel oil storage tank internal foam nozzle and deflector, prior to the second period of extended operation, to ensure proper configuration and orientation and no indication of flow blockage. 12. Perform an internal inspection of the auxiliary boiler oil storage tank foam system foam concentrate tank every 10 years to ensure it is free of corrosion, debris, or foreign material that could cause flow blockage, and to ensure there are no cracks or leaks and it is in good condition. 13. Revise restoration procedures for the hydrogen seal oil and reactor building water curtain systems to utilize low point drains following control valve actuations to ensure there is no trapped water in the system. 14. Revise restoration procedures for the yard transformer deluge systems to utilize low point drains after functional testing.		
18	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks is an existing program that will be enhanced to: 1. Perform a visual inspection of the sealant at the perimeter of the condensate storage tanks and refueling water storage tank bases for signs of degradation every two years. The visual inspections of sealant and caulking are supplemented with physical manipulation to detect degradation. 2. Perform a pre-inspection review of the previous two inspections of the internal tank coatings, when available, that includes review of results of inspections and any subsequent repair activities. 3. Conduct training and qualification of individuals involved in internal coating or lining inspections and evaluating degraded conditions in accordance with an ASTM International standard endorsed in RG 1.54. 4. Perform volumetric inspection of Unit 2 and 3 condensate storage tanks and refueling water storage tank bottoms at least once during the 10-year period prior to the second period of extended operation, and at least once every 10 years during the second period of extended operation. Volumetric inspections are performed at representative sample locations	Program will be enhanced no later than six months prior to the second period of extended operation, unless a more specific schedule is described within the enhancement (i.e., Enhancement 4). Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to	Section A.2.1.18

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

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NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		to include 25 one square foot locations or 20 percent coverage conducted in different locations unless the program states the basis for why repeated inspections are conducted in the same location (i.e. previous findings). Additionally, a minimum of 10 of the random one square foot sample locations will be performed within the 30-inch band at the perimeter of the shell. The scope of subsequent examinations may be adjusted based upon the results of previous examinations.	the second period of extended operation.	
19	Fuel Oil Chemistry	Fuel Oil Chemistry is an existing program that will be enhanced to: 1. Perform periodic internal inspection of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543) at least once during the 10-year period prior to the second period of extended operation, and at least once every 10 years during the second period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected. 2. Perform periodic (quarterly) removal of water collected at the bottom of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543). 3. Perform receipt testing of new fuel oil for particulate concentration and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040), diesel generator fuel oil storage tanks (0A(B,C,D)T038), and diesel fire pump fuel oil storage tank (00T041). 4. Perform periodic (quarterly) sampling and analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040). Sampling activities will include a sampling methodology that includes a representative sample from the lowest point in the tank. 5. Perform periodic (quarterly) sampling and analysis for water and sediment and the levels of microbiological organisms for the diesel generator fuel oil storage tanks (0A(B,C,D)T038). 6. Perform periodic (quarterly) sampling and analysis for particulate concentration and the levels of microbiological organisms for the diesel fire	Program will be enhanced no later than six months prior to the second period of extended operation unless a more specific schedule is described within the enhancement (i.e., Enhancement 1). Inspections that are to be completed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.19

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543). 7. Perform periodic (quarterly) trending of water and sediment content, particulate concentration, and the levels of microbiological organisms for all fuel oil tanks within the scope of the program. 8. Evaluate the need for biocide or corrosion inhibitor addition if periodic testing indicates biological activity or evidence of corrosion. 9. Evaluate degradation identified during tank internal inspections against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended function throughout the second period of extended operation based on the projected rate of degradation.		
20	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance is an existing program that will be enhanced to: 1. Withdraw and test the Unit 2, 120 degree reconstituted capsule and the Unit 3, 120 degree capsule per the capsule withdrawal schedules below. A technical summary report containing the test results shall be submitted to the NRC per the requirements of 10 CFR Part 50, Appendix H. Any changes to the Reactor Vessel Material Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.	Enhancement 1 will be implemented in accordance with the schedules defined in the commitment.	Section A.2.1.20

Peach Bottom Unit 2 Capsule Withdrawal Schedule

Capsule	Capsule Lead Factor (0T/¼T)	Capsule Withdrawal EFPY
30°	0.95/1.38	Per BWRVIP-86-R1-A
120°	0.95/1.38	7.53 (actual)
120° Reconstituted	0.95/1.38	60 - 62(1)
300°	0.95/1.38	Per BWRVIP-86-R1-A

1. Capsule 120° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.21 EFPY less than plant operating EFPY.

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033   Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		(see capsule withdrawal schedule and notes below)		

Peach Bottom Unit 3 Capsule Withdrawal Schedule		
Capsule	Capsule Lead Factor (0T/¼T)	Capsule Withdrawal EFPY
30°	0.95/1.38	7.57 (actual)
30° Reconstituted	0.95/1.38	Spare(1)
120°	0.95/1.38	60 - 62
300°	0.95/1.38	Spare(2)

1. Capsule 30° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating EFPY.
2. Capsule 300° was withdrawn after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating EFPY.

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
21	One-Time Inspection	One-Time Inspection aging management program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the second period of extended operation; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.	Program will be implemented no later than 10 years prior to the second period of extended operation. The one-time inspections are required to be performed within the 10 years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.21

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
22	Selective Leaching	Selective Leaching aging management program is a new condition monitoring program that will monitor components constructed of materials which are susceptible to selective leaching. The selective leaching program includes a one-time inspection for susceptible components exposed to closed cycle cooling water and treated water environment since plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments.	Program will be implemented no later than 10 years prior to the second period of extended operation. The one-time inspections and initial periodic inspections are required to be performed within the 10 years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.22

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
23	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) that have experienced cracking and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking.	Program will be implemented no later than six years prior to the second period of extended operation. The one-time inspections are required to be performed within the six years prior to the second period of extended operation, and no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.23
24	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material, cracking, and hardening and loss of strength for elastomeric components, loss of preload for HVAC closure bolting, and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic components, elastomers, and insulation jacketing (insulation when not jacketed) will be conducted.	Program will be implemented no later than six months prior to the second period of extended operation.	Section A.2.1.24

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material and hardening and loss of strength of elastomeric materials. Reduction of heat transfer will also be managed. This program will consist of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, and other mechanical components.	Program will be implemented no later than six months prior to the second period of extended operation.	Section A.2.1.25
26	Lubricating Oil Analysis	Existing program is credited.	Ongoing	Section A.2.1.26
27	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Existing program is credited.	Ongoing	Section A.2.1.27
28	Buried and Underground Piping and Tanks	Buried and Underground Piping is an existing program that will be enhanced to: 1. Manage cracking for buried stainless steel piping, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed exposing the base material. 2. Perform direct visual inspection of buried piping within the scope of license renewal in accordance with NUREG-2191, Table XI.M41-2, and sections 4.a and 4.b, during each 10-year period, beginning 10 years prior to the second period of extended operation. The number of inspections of buried piping will be based upon the as-found results of cathodic protection system availability and effectiveness. The length of piping for each inspection will be based on the recommendations in section 4.c. 3. Perform extent of condition inspections as follows: When measured pipe wall thickness, projected to the end of the second period of extended operation, does not meet the minimum pipe wall thickness requirements due to external environments, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-up inspections will be determined based	Program will be enhanced no later than 10 years prior to the second period of extended operation, unless a more specific schedule is described within the enhancement (i.e., Enhancement 4). Inspections that are required to be performed in the 10-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last	Section A.2.1.28

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval. 4. Upgrade existing cathodic protection system no later than 5 years prior to the second period of extended operation, in accordance with NACE SP0169-2007, to ensure effective control of external corrosion of underground piping and tanks. 5. Perform examination of buried emergency diesel generator fuel oil tanks from the internal surface of the tank using volumetric techniques during each 10-year period, beginning 10 years prior to the second period of extended operation. A minimum of 25 percent coverage is required. 6. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping. 7. Apply coating to buried portions of the 10-inch diameter stainless steel line from the torus dewatering tank to the condensate transfer pump suction line in accordance with approved station specifications, during the 10-year period prior to the second period of extended operation.	refueling outage prior to the second period of extended operation.	

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
29	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 aging management program is a new condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, waste water, condensation, or lubricating oil that can lead to loss of material of base metals or downstream effects such as reduction in flow, pressure, or heat transfer when coatings/linings become debris.	Program will be implemented no later than 10 years prior to the second period of extended operation. Baseline inspections that may be required in the 10-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.29
30	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE is an existing program that will be enhanced to: 1. Perform surface examinations on accessible portions of high temperature drywell mechanical penetrations, in addition to visual examinations, to detect cracking, once per 10-year interval during the second period of extended operation.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.30

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033   Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
31	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF is an existing program that will be enhanced to: 1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the second period of extended operation. 2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. Conduct the one-time inspection within the five years prior to entering the second period of extended operation. Select the additional supports from the remaining population of IWF piping supports. Ensure that the sample expansion includes components that are most susceptible to age-related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment). 3. Perform VT-3 examinations of all ASTM A-490 bolting materials, used for the reactor vessel support skirts and for the core spray pump supports once per 10-year interval during the second period of extended operation. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of 12 ASTM A490 bolts at each of the reactor vessel support skirts, once per 10-year interval during the second period of extended operation.	Program will be enhanced in accordance with the schedule described within the enhancements. Inspections that are required to be performed in the five-year period prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.31
32	10 CFR Part 50, Appendix J	Existing program is credited.	Ongoing	Section A.2.1.32
33	Masonry Walls	Masonry Walls is an existing program that will be enhanced to: 1. Expand the program to include masonry walls in the Administration Building and Dewatering Building.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.33

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
34	Structures Monitoring	Structures Monitoring is an existing program that will be enhanced to: 1. Explicitly include the following components and commodities within the scope of the program: a. Bearing pads for supports b. Electrical duct banks c. Electrical raceway such as cable tray, conduit, and wireway gutter d. Hatches and plugs e. Manholes and handholes f. Miscellaneous components such as louvers g. Panels, racks, frames, cabinets, and other enclosures h. Permanent shielding blankets 2. Add the following structures to the scope of the program: a. Administration Building b. Boiler House c. Dewatering Building 3. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation. 4. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R. 5. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified. 6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if	Program will be enhanced no later than six months prior to the second period of extended operation. Baseline inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.34

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. 7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. 8. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant loss of material due to wear or corrosion, and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design. 9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas 10. Expand the program to monitor elastomeric vibration isolators and bearing pads for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection to detect hardening, if the intended function is suspect. Establish acceptance criteria for elastomeric pads and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of isolation or support function. 11. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations.		

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		12. Expand the program to inspect the fiberglass outer covering of permanent shielding blankets for signs of tears. If a tear is found, enter the condition into the corrective action program for evaluation. Repair or replace the permanent shielding, unless an evaluation determines that the condition is acceptable.		
35	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to: 1. Explicitly include the sluice gates at the Circulating Water Pump Structure within the scope of the program. 2. Clarify parameters to be monitored and inspected at the Emergency Cooling Tower and Reservoir to include visual inspection for loss of material and reduction of heat transfer due to fouling for the cooling tower fill, and visual inspection of the drift eliminators. 3. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified. 4. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. 5. Include provisions for special inspections following significant natural phenomena, such as large floods, hurricanes, tornadoes, or intense local rainfall as part of the guidelines for severe weather and natural disasters. 6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced	Program will be enhanced no later than six months prior to the second period of extended operation. Baseline inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.35

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. 7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. 8. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 9. Document the concrete conditions of submerged concrete structures. 10. Specify a six-year frequency for the inspection of the submerged portions of the traveling screen bays to match the inspection frequency of the submerged portions of the Circulating Water Pump Structure bays. 11. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation. 12. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R. 13. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations.		
36	Protective Coating Monitoring and Maintenance Program	Protective Coating Monitoring and Maintenance Program is an existing program that will be enhanced to: 1. Use certified coating inspectors for the inspection of Service Level I coatings.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.1.36

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is an existing program that will be enhanced to: 1. Include potential follow-up actions when visual inspections identify degraded or damaged conditions that may impact the performance of intended functions: a. Perform tests, for condition monitoring when visual inspections identify damaged or degraded insulation of in scope cables and connections. When a large number of cables are identified as damaged or degraded, a sample population will be tested. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25. b. Document the basis for the samples selected for testing when visual inspections identify damaged or degraded insulation conditions for in scope cables and connections. 2. Visually inspect and evaluate cables and connections that were exposed to adverse localized environments (ALEs), which have since been mitigated, on an at least once every 10-year frequency, to assure the cumulative aging effects for electrical insulation, in remedied ALEs are not impacting the ongoing ability of the cables and connections to perform their intended function during the second period of extended operation.	Program will be enhanced no later than six months prior to the second period of extended operation. In addition, the first inspections incorporating enhancements will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.37
38	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is an existing program that will be enhanced to: 1. Add the following radiation monitors to the scope of this program a. Main steam line radiation monitors b. Reactor building ventilation exhaust radiation monitors c. Control room fresh air supply radiation monitors d. Control room emergency ventilation supply radiation monitors e. Main stack radiation monitors.	Program will be enhanced no later than six months prior to the second period of extended operation. The first documented periodic review will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling	Section A.2.1.38

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Peach Bottom Atomic Power Station Unit 2: August 8, 2033 Peach Bottom Atomic Power Station Unit 3: July 2, 2034

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		2. 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. Perform the first periodic review for second license renewal prior to the second period of extended operation and at least every 10 years thereafter.	outage prior to the second period of extended operation.	
39	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is an existing program that will be enhanced to: 1. Add periodic cable testing for additional circuits. 2. Perform cable testing of the circuits in the scope of this program at a frequency of at least once every six years. 3. Add periodic condition monitoring, as a preventive action, for manholes.	Program will be enhanced no later than six months prior to the second period of extended operation. Tests and inspections that are required to be performed prior to the second period of extended operation will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.39

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NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
40	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture.	Program will be implemented no later than six months prior to the second period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.40
41	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low-voltage power cables (operating voltage less than 2 kV), exposed to significant moisture.	Program will be implemented no later than six months prior to the period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.41

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NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
42	Metal Enclosed Bus	Metal Enclosed Bus aging management program is a new condition monitoring program that uses sampling and will manage the identified aging effects of in scope metal enclosed bus.	Program will be implemented no later than six months prior to the second period of extended operation. Initial inspections and resistance measurements will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.42
43	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 aging management program is a new condition monitoring program that consists of a representative sample of electrical connections tested prior to the second period of extended operation. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency.	Program will be implemented no later than six months prior to the second period of extended operation. Testing and evaluation of results will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.2.1.43

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NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
44	Wooden Pole	Wooden Pole is an existing program that will be enhanced to: 1. Document results that do not meet the acceptance criteria in the corrective action program.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.2.2.1
45	Fatigue Monitoring	Fatigue Monitoring is an existing program that will be enhanced to: 1. Update the SI:FatiguePro™ software to include the calculation and tracking of Environmentally Assisted Fatigue (EAF) in accordance NUREG/CR-6909, Revision 1. 2. Update applicable fatigue analyses and monitored component locations based on operating experience, plant modifications, inspection findings, changes to transient definitions, and unanticipated newly discovered fatigue loading events. 3. Provide procedural direction to require periodic validation of chemistry parameters used to determine Fen factors used in SI:FatiguePro™. 4. Provide procedural direction to add an additional acceptance criterion associated with HELB exclusion criteria.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.3.1.1
46	Neutron Fluence Monitoring	Neutron Fluence Monitoring is an existing program that will be enhanced to: 1. Perform periodic monitoring of reactor pressure vessel and reactor vessel internals accumulated neutron fluence, every refueling cycle, to ensure that neutron fluence projections used to support reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs, pressure-temperature limits) and reactor vessel internals aging effect assessments remain bounding with respect to actual plant operating conditions.	Program will be enhanced no later than six months prior to the second period of extended operation.	Section A.3.1.2

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NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
47	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment is an existing program that will be enhanced to: 1. Add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the second period of extended operation. 2. Establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments.	Program will be enhanced no later than six months prior to the second period of extended operation. New visual inspections of accessible, passive EQ equipment located in adverse localized environments will be completed no later than six months prior to the second period of extended operation, or no later than the last refueling outage prior to the second period of extended operation.	Section A.3.1.3
48	Operating Experience	Existing program is credited.	Ongoing	Section A.1.6
49	Operating Experience Review	Exelon will perform an evaluation of operating experience at extended power uprate (EPU) levels prior to the period of extended operation to ensure that operating experience at EPU levels is properly addressed by the aging management programs. The evaluation will include Peach Bottom and other BWR plants operating at EPU levels.	Evaluation will be completed no later than six months prior to the second period of extended operation.	NUREG-2192 Section 1.2.2
50	FERC Inspections of the Conowingo Hydroelectric Plant (Dam)	Existing program is credited.	Ongoing	FERC No. 405 NUREG-2191 Section XI.S7

* The dates for the start of the respective second periods of extended operation for Peach Bottom Atomic Power Station, Units 2 and 3 are:

Peach Bottom Atomic Power Station Unit 2: August 8, 2033   Peach Bottom Atomic Power Station Unit 3: July 2, 2034

APPENDIX B AGING MANAGEMENT PROGRAMS
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B.1 INTRODUCTION

B.1.1 OVERVIEW

Second license renewal Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this application.

In general, there are four types of AMPs:

- Prevention programs preclude aging effects from occurring.
- Mitigation programs slow the effects of aging.
- Condition monitoring programs inspect/examine for the presence and extent of aging.
- Performance monitoring programs test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for a component to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has 10 elements which are consistent with the attributes described in Appendix A.1, "Aging Management Review – Generic (Branch Technical Position RLSB-1)" and in Table A.1-1 "Elements of an Aging Management Program for Subsequent License Renewal" of NUREG-2192. The 10-element detail is not provided when the program is deemed to be consistent with the assumptions made in NUREG-2191. The 10-element detail is only provided when the program is plant-specific.

Credit has been taken for existing plant programs whenever possible. As such, all programs and activities associated with a system, structure, component, or commodity grouping were considered. Existing programs and activities that apply to systems, structures, components, or commodity groupings were reviewed to determine whether they include the necessary actions to manage the effects of aging.

Existing plant programs may have been based on a regulatory commitment or requirement, or aging management activities credited for the first license renewal, or a combination of both. Many of these existing programs included the required license renewal 10-element attributes, and have been demonstrated to adequately manage the identified aging effects. If an existing program did not adequately manage an identified aging effect, the program was enhanced as necessary. Occasionally, the creation of a new program was necessary.

B.1.2 Method of Discussion

For those AMPs that are consistent with the assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each program discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided.
- A NUREG-2191 consistency statement is made about the program.
- Exceptions to the NUREG-2191 program are outlined and a justification for the exceptions is provided.
- Enhancements or additions to the PBAPS program are provided. Refer to Appendix A for implementation schedule information.
- Operating Experience (OE) information specific to the program is provided.
- A Conclusion section provides a statement of reasonable assurance that the program is effective, or will be effective when implemented, if new or enhanced.

The plant-specific AMPs are described in terms of the 10 program elements in NUREG-2192, Section A.1.2.3 “Aging Management Program Elements”.

B.1.3 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR. Generically, the three elements are applicable as follows:

Corrective Actions:

A single corrective action program is applied regardless of the safety classification of the system, structure, component, or commodity group. Corrective actions are implemented through the initiation of an issue report (IR) in accordance with the Corrective Action Program in place to meet the requirements of 10 CFR 50, Appendix B. The Corrective Action Program requires the initiation of an IR for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement aging management programs for license renewal direct that an IR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met).

Equipment deficiencies are corrected through the Work Control Process in accordance with plant procedures. The Corrective Action Program specifies that an IR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The Corrective Action Program implements the requirements of NO-AA-10, the Exelon Quality Assurance Topical Report (QATR), Chapter 16, “Corrective Action.” Specifically, conditions adverse to quality and significant conditions adverse to quality are resolved through direct action, the implementation of corrective actions, and where appropriate, the implementation of corrective actions to prevent recurrence.

Confirmation Process:

The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting and precluding repetition of adverse conditions. The Corrective Action Program includes provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). The Corrective Action Program provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The Corrective Action Program also includes monitoring for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions results in the initiation of an IR. The aging management programs required for second license renewal would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related systems, structures, and components subject to AMR for second license renewal, the Corrective Action Program is consistent with the NUREG-2191 elements.

Administrative Controls:

The document control process applies to all generated documents, procedures, and instructions regardless of the safety classification of the associated system, structure, component, or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants.” Implementation is further defined in NO-AA-10, the Exelon Quality Assurance Topical Report (QATR), Chapter 6, “Document Control.”

Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and as-building frequency. Revisions will be made to procedures and instructions that implement or administer aging management program requirements for the purposes of managing the associated aging effects for the second period of extended operation.

B.1.4 Operating Experience

Operating experience from internal (also referred to as plant-specific) and external (also referred to as industry) sources is captured and systematically reviewed on an ongoing basis in accordance with the Quality Assurance program, which meets the requirements of 10 CFR Appendix B, and the Operating Experience (OPEX) program, which meets the requirements of NUREG- 0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The OPEX program interfaces with and relies on active participation in the "Institute of Nuclear Power Operations" Operating Experience program, as endorsed by the NRC.

Operating experience is used at PBAPS to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants. As part of the Exelon fleet, PBAPS personnel receive operating experience (internal and external to Exelon Nuclear) daily. The OPEX process includes screening, evaluation, and acting on operating experience documents and information to prevent or mitigate the consequences of similar events. The OPEX process includes review of operating experience from external and internal sources. External operating experience includes INPO documents, NRC documents (e.g., GALL Revisions, Information Notices, Regulatory Information Summaries, Interim Staff Guidance), and other documents (e.g., Licensee Event Reports, 10 CFR Part 21 Reports), as well as relevant research and development information. Internal operating experience includes event investigations, trending reports, and lessons learned from in-house events as captured in program health reports, program assessments, and in the 10 CFR Part 50, Appendix B corrective action program.

The Exelon fleet OPEX program that is implemented at PBAPS is an ongoing program that conforms to the recommendations of LR-ISG-2011-05, "Ongoing Review of Operating Experience," and is consistent with the expectations outlined in NUREG-2192 (SRP-SLR), Appendix A.4, "Operating Experience for Aging Management Programs." The systematic review of plant-specific and industry operating experience concerning aging management and age-related degradation ensures that the license renewal aging management programs (AMPs) are, and will continue to be, effective in managing the aging effects for which they are credited. Operating experience involving age-related degradation is tracked and trended such that adverse trends are entered into the corrective action program for evaluation. Potential aging issues associated with SSCs within the scope of license renewal are evaluated with regard to: (a) materials of construction, (b) operating environment, (c) aging effects, (d) aging mechanisms, and (e) aging management programs, to determine if changes to AMPs, or new AMPs are needed. The AMPs are either enhanced or new AMPs developed, as appropriate, when it is determined through the evaluation of operating experience that the effects of aging may not be adequately managed. AMPs are informed by the review of operating experience on an ongoing basis, regardless of the AMP's implementation schedule. The Exelon process directs the reporting of plant-specific operating experience on age-related degradation and aging management to the industry through the INPO OPEX program, consistent with the guidance in NEI 14-13, "Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs." In addition, the Exelon process requires the periodic conduct of AMP effectiveness reviews, such that they are performed at least once within every five-year period, and refers to and is consistent with the guidance of NEI 14-12, "Aging Management Program Effectiveness."

Each AMP summary in this appendix contains a discussion of operating experience relevant to the program. This information was obtained through the review of internal operating experience captured by the corrective action program, program assessments, program health reports, and through the review of external operating experience. Additionally, operating experience was obtained through interviews with system engineers, program engineers, and other plant personnel. New programs utilized internal and/or external operating experience as applicable, and the AMP summaries in this appendix discuss the operating experience and associated corrective actions as they relate to implementation of the new program. The operating experience in each AMP summary identifies past corrective actions, some of which have resulted in program enhancements and provides objective evidence that the effects of aging have been, and will continue to be, adequately managed so that the intended functions of the structures and components within the scope of each program will be maintained during the second period of extended operation.

Consistent with the guidance in Section 6 of Appendix B of NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," effectiveness reviews of first license renewal aging management programs/activities (i.e., FLR AMPs) were performed, and are presented within the SLRA Appendix B AMP sub-sections that are most related to those FLR AMPs. For example, there were several FLR AMPs related to water chemistry control. An assessment of the effectiveness of these is presented within Section B.2.1.2, which describes the SLR AMP for the Water Chemistry aging management program. These effectiveness reviews are presented as the first operating experience example in the related SLRA AMP operating experience section (i.e., as OE #1). As applicable, these effectiveness review summaries may reveal such things as: 1) whether significant plant OE was identified due to AMP implementation, 2) whether significant relevant plant OE occurred that was not identified through AMP implementation, 3) how internal or external OE was used to inform or enhance the AMP, and 4) how the effectiveness of the AMP is being monitored.

B.1.5 NUREG-2191 Chapter XI Aging Management Programs

The following AMPs are described in the sections listed in this appendix. The programs are either generic in nature as discussed in NUREG-2191, Section XI, or are plant-specific. NUREG-2191 Chapter XI programs are listed in Section B.2.1. Plant-specific programs are listed in Section B.2.2. All generic programs are fully consistent with or are, with identified exceptions, consistent with programs discussed in NUREG-2191. Programs are identified as either existing or new.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1) [Existing]
2. Water Chemistry (Section B.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section B.2.1.3) [Existing]
4. BWR Vessel ID Attachment Welds (Section B.2.1.4) [Existing]
5. BWR Stress Corrosion Cracking (Section B.2.1.5) [Existing]
6. BWR Penetrations (Section B.2.1.6) [Existing]
7. BWR Vessel Internals (Section B.2.1.7) [Existing - Requires Enhancement]
8. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section B.2.1.8) [New]
9. Flow-Accelerated Corrosion (Section B.2.1.9) [Existing - Requires Enhancement]
10. Bolting Integrity (Section B.2.1.10) [Existing - Requires Enhancement]
11. Open-Cycle Cooling Water System (Section B.2.1.11) [Existing - Requires Enhancement]
12. Closed Treated Water Systems (Section B.2.1.12) [Existing - Requires Enhancement]
13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section B.2.1.13) [Existing - Requires Enhancement]
14. Compressed Air Monitoring (Section B.2.1.14) [Existing - Requires Enhancement]
15. BWR Reactor Water Cleanup System (Section B.2.1.15) [Existing]
16. Fire Protection (Section B.2.1.16) [Existing - Requires Enhancement]
17. Fire Water System (Section B.2.1.17) [Existing - Requires Enhancement]
18. Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.1.18) [Existing - Requires Enhancement]

19. Fuel Oil Chemistry (Section B.2.1.19) [Existing - Requires Enhancement]
20. Reactor Vessel Material Surveillance (Section B.2.1.20) [Existing - Requires Enhancement]
21. One-Time Inspection (Section B.2.1.21) [New]
22. Selective Leaching (Section B.2.1.22) [New]
23. ASME Code Class 1 Small-Bore Piping (Section B.2.1.23) [New]
24. External Surfaces Monitoring of Mechanical Components (Section B.2.1.24) [New]
25. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.25) [New]
26. Lubricating Oil Analysis (Section B.2.1.26) [Existing]
27. Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section B.2.1.27) [Existing]
28. Buried and Underground Piping and Tanks (Section B.2.1.28) [Existing - Requires Enhancement]
29. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.1.29) [New]
30. ASME Section XI, Subsection IWE (Section B.2.1.30) [Existing - Requires Enhancement]
31. ASME Section XI, Subsection IWF (Section B.2.1.31) [Existing - Requires Enhancement]
32. 10 CFR Part 50, Appendix J (Section B.2.1.32) [Existing]
33. Masonry Walls (Section B.2.1.33) [Existing - Requires Enhancement]
34. Structures Monitoring (Section B.2.1.34) [Existing - Requires Enhancement]
35. Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.1.35) [Existing - Requires Enhancement]
36. Protective Coating Monitoring and Maintenance (Section B.2.1.36) [Existing - Requires Enhancement]
37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.37) [Existing - Requires Enhancement]
38. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in

Instrumentation Circuits (Section B.2.1.38) [Existing - Requires Enhancement]

39. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.39) [Existing - Requires Enhancement]

40. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.40) [New]

41. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.41) [New]

42. Metal Enclosed Bus (Section B.2.1.42) [New]

43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.43) [New]

B.1.6 Plant-Specific Aging Management Programs

The following plant-specific aging management program is described in Section B.2.2 of this appendix as indicated. The program is identified as either existing or new.

1. Wooden Pole (Section B.2.2.1) [Existing - Requires Enhancement]

B.1.7 NUREG-2191 Chapter X Aging Management Programs

The following NUREG-2191 Chapter X AMPs are described in Section B.3 of this appendix as indicated. Programs are identified as either existing or new.

1. Fatigue Monitoring (Section B.3.1.1) [Existing - Requires Enhancement]

2. Neutron Fluence Monitoring (Section B.3.1.2) [Existing - Requires Enhancement]

3. Environmental Qualification of Electric Equipment (Section B.3.1.3) [Existing - Requires Enhancement]

B.2 Aging Management Programs

B.2.0 NUREG-2191 Aging Management Program Correlation

The correlation between the NUREG-2191 (Generic Aging Lessons Learned (GALL-SLR)) programs and the PBAPS Aging Management Programs (AMPs) is shown below. Links to the sections describing the PBAPS programs are provided.

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	PBAPS PROGRAM
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.1.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (Section B.2.1.3)
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds (Section B.2.1.4)
XI.M5	Deleted	Not Applicable.
XI.M6	Deleted	Not Applicable.
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking (Section B.2.1.5)
XI.M8	BWR Penetrations	BWR Penetrations (Section B.2.1.6)
XI.M9	BWR Vessel Internals	BWR Vessel Internals (Section B.2.1.7)
XI.M10	Boric Acid Corrosion	Not Applicable. (PBAPS Units 2 and 3 are BWRs)
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Not Applicable. (PBAPS Units 2 and 3 are BWRs)
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section B.2.1.8)
XI.M16A	PWR Vessel Internals	Not Applicable. (PBAPS Units 2 and 3 are BWRs)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.1.9)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	PBAPS PROGRAM
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.1.10)
XI.M19	Steam Generators	Not Applicable. (PBAPS Units 2 and 3 are BWRs)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.1.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (Section B.2.1.12)
XI.M22	Boraflex Monitoring	Not Applicable. (This program is not credited for aging management. Boraflex is not a credited neutron-absorbing material in the PBAPS spent fuel pool racks.)
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section B.2.1.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.1.14)
XI.M25	BWR Reactor Water Cleanup System	BWR Reactor Water Cleanup System (Section B.2.1.15)
XI.M26	Fire Protection	Fire Protection (Section B.2.1.16)
XI.M27	Fire Water System	Fire Water System (Section B.2.1.17)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.1.18)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.1.19)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (Section B.2.1.20)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.1.21)
XI.M33	Selective Leaching	Selective Leaching (Section B.2.1.22)
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping (Section B.2.1.23)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (Section B.2.1.24)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	PBAPS PROGRAM
XI.M37	Flux Thimble Tube Inspection	Not Applicable. (PBAPS Units 2 and 3 are BWRs)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.25)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.1.26)
XI.M40	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Monitoring of Neutron-Absorbing Materials Other than Boraflex (Section B.2.1.27)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (Section B.2.1.28)
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.1.29)
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.1.30)
XI.S2	ASME Section XI, Subsection IWL	Not Applicable. (PBAPS Units 2 and 3 do not have reinforced prestressed concrete containments)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.1.31)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (Section B.2.1.32)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.1.33)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.1.34)
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.1.35)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.1.36)
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.37)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	PBAPS PROGRAM
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B.2.1.38)
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.39)
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.40)
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.41)
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus (Section B.2.1.42)
XI.E5	Fuse Holders	Not Applicable. (The metallic clamp portions of fuse holders have no aging effects requiring management.)
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.43)
XI.E7	High-Voltage Insulators	Not applicable. (The High-Voltage Insulators have no aging effects requiring management.)
X.M1	Fatigue Monitoring	Fatigue Monitoring (Section B.3.1.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (Section B.3.1.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Not Applicable. (PBAPS Units 2 and 3 do not have containments with prestressed tendons)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.3.1.3)
N/A	Peach Bottom Plant-Specific Program	Wooden Pole (Section B.2.2.1)

B.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter XI programs credited for managing the effects of aging.

B.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition monitoring program which manages the aging effects of cracking, loss of material, loss of fracture toughness, and loss of preload for pressure-retaining bolting in Class 1, 2, and 3 piping and components exposed to a reactor coolant or treated water environment. This program includes periodic visual, surface, and volumetric examination of Class 1, 2, and 3 pressure-retaining components. The program implements the Inservice Inspection (ISI) requirements of ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components, their integral attachments, and pressure-retaining bolting. Examination of these components is in accordance with Subsections IWB, IWC, and IWD respectively.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program includes augmented inservice inspection requirements for periodic examination of the reactor vessel feedwater nozzles in accordance with the staff-approved recommendations provided within BWR Owners Group (BWROG) Licensing Topical Report, “Alternate BWR Feedwater Nozzle Inspection Requirements,” GE-NE-523-A71-0594-A, Revision 1, May 2000.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program implements the required component examination schedule per ASME Section XI, Subsection IWB-2400, IWC-2400, or IWD-2400 and examination categories, applicable components, examination methods, acceptance standards, and frequency of examination as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The examination methods specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are based on approved industry standards for detecting degradation of components. Indications and relevant conditions detected during examinations are entered into the corrective action program and evaluated in accordance with ASME Section XI, Articles IWB-3000 for Class 1, IWC-3000 for Class 2, and IWD-3000 for Class 3. The program directs that repair and replacement activities be performed in conformance with IWA-4000.

For the current fourth 10-year inspection interval, the ISI program applies the requirements of ASME Code, Section XI, 2001 Edition through 2003 Addenda, and Risk-Informed Inservice Inspection (RI-ISI) alternative requirements to Examination Categories B-F, B-J, C-F-1, and C-F-2 for Class 1 and Class 2 piping welds as approved by relief request. Examination locations, and the number of locations requiring examination, are based on the guidelines provided in EPRI TR-112657, “Revised Risk-Informed Inservice Inspection Evaluation Procedure,” Revision B-A, and ASME Code Case N-578-1.

In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval. Any deviation from ASME Code, Section XI requirements must be approved by the NRC per a relief request.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes all component inspection activity required by ASME Code, Section XI, Subsections IWB, IWC, and IWD except for those components that are covered by the following license renewal aging management programs that include augmented requirements:

- Reactor Head Closure Stud Bolting (B.2.1.3)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Stress Corrosion Cracking (B.2.1.5)
- BWR Penetrations (B.2.1.6)
- BWR Vessel Internals (B.2.1.7)
- BWR Reactor Water Cleanup System (B.2.1.15)
- ASME Code Class 1 Small-Bore Piping (B.2.1.23)

NUREG-2191 Consistency

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is consistent with the ten elements of aging management program XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the Risk-Informed Inservice Inspection (RI-ISI) portion of the Inservice Inspection (ISI) Program described in UFSAR Section Q.1.8. This review was performed in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage aging effects including cracking of pressure-

retaining piping that is within the scope of ASME Code Section XI, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of inspection records and remaining inspection schedules during the fourth 10-year ISI inspection interval (November 2008 through December 2018). The review also included pertinent issues found in the corrective action program from 2001 to 2016, searching for age-related degradation of components within the scope of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD aging management program.

The review identified that inspections of piping components within the scope of the RI-ISI portion of the Inservice Inspection (ISI) Program are being performed in accordance with extent and schedule described in EPRI TR-112657, Revision B-A as supplemented by ASME Code Case N-578-1. The review identified that inspections performed within the program are effective at identifying age-related degradation of in scope components. Age-related issues were evaluated in accordance with ASME Code Section XI requirements resulting in effective implementation of this aging management program. The review also concludes that the piping welds within the scope of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD aging management program are in excellent condition on Units 2 and 3.

This operating experience provides objective evidence that the current Inservice Inspection (ISI) Program is being effectively implemented to manage aging effects. Continued implementation of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD aging management program will assure that the piping welds within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. In 2015, a focused area self-assessment of the ISI program identified that the inspection of Unit 2 RHR heat exchanger shell welds were not scheduled for the fourth 10-year ISI interval in accordance with ASME Code, Section XI, Table IWC-2500-1, Examination Category C-A, and IWC-2400 requirements. Periodic self-assessment of the ISI program is required every five years. The assessment identified that two welds on the same RHR heat exchanger were both scheduled to be performed during the third period of the fourth 10-year interval, whereas IWC-2400 requires that if there are less than three welds to be examined, they must be examined in any two periods within the interval. The issue was entered into the corrective action program. To address the issue, the second period of the fourth interval was extended by 10 months, as allowed by IWA-2430, and one of the RHR heat exchanger shell welds was examined within the revised second period. The second RHR heat exchanger shell weld is scheduled to be examined during the third period of the fourth interval.

This operating experience provides objective evidence that the process of performing periodic self-assessment of the ISI program is effective at identifying deficiencies in program implementation and the corrective action program is effectively used to implement actions to correct identified deficiencies. Continued implementation of the ASME Section XI, Inservice

Inspection, Subsections IWB, IWC, and IWD aging management program, including performing periodic self-assessment, will assure that the ISI program will continue to be implemented in accordance with program requirements during the second period of extended operation.

3. In 2010, volumetric examination of the Unit 2 reactor vessel head to flange weld, CH-C-2, identified nine indications in the weld region. The condition was entered into the corrective action program. Eight of the indications were evaluated as acceptable based on ASME Code Section XI, Table IWB-3510-1 criteria. One indication was determined to be a sub-surface flaw that was previously identified and analytically evaluated in accordance with the requirements in IWB-3600 in 2002. This indication did not meet Table IWB-3510-1 criteria and its geometry had changed due to more accurate inspection techniques used in 2010. Therefore, the indication was re-evaluated based on IWB-3600 guidance. Review of the fracture mechanics evaluation performed in 2002 determined that the results were bounding for the indication as measured in 2010. This evaluation included consideration of flaw growth and concluded that the flaw is acceptable for continued operation through the 60-year period of extended operation. The analytical evaluation was submitted to the NRC for review in accordance with ASME Code Section XI, IWB-3134(b). This flaw growth evaluation is addressed as a TLAA in Section 4.3.8.

This example provides objective evidence that the ISI program implements volumetric examination of reactor vessel welds using the method required by ASME Code Section XI. This example also illustrates that ISI examinations performed by qualified personnel are capable of detecting flaws and other indications of possible age-related degradation. This example also demonstrates that deficiencies are entered into the corrective action program and actions are taken in to evaluate deficiencies accordance with ASME Code Section XI requirements.

4. During the fourth 10-year ISI interval between November 2008 and December 2018, examinations of the reactor vessel feedwater nozzles including inner radii and nozzle bore were performed. The Unit 2 “A” and “C” nozzles were examined in 2010; the “B” nozzle was examined in 2012; and the “D”, “E”, and “F” nozzles were examined in 2014, using volumetric examination methods. The Unit 3 “E” and “F” nozzles were examined in 2009; the “A” and “B” nozzles were examined in 2011; and the “C” and “D” nozzles were examined in 2013, using volumetric examination methods. No cracking indications were identified by any of the examinations.

This example provides objective evidence that the ISI program implements augmented volumetric examination of the reactor vessel feedwater nozzles in accordance with BWROG Licensing Topical Report, GE-NE-523-A71-0594-A, Revision 1, and ASME Code Section XI. This example also illustrates that the Unit 2 and Unit 3 feedwater nozzles are in excellent material condition and that continued implementation of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD aging management program will assure that they will continue to perform their intended functions during the second period of extended operation.

The operating experience relative to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of fracture toughness, loss of preload, and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.2 Water Chemistry

Program Description

The Water Chemistry aging management program is an existing program whose activities mitigate the loss of material due to corrosion, cracking due to stress cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environment. The program includes periodic monitoring and trending of the treated water and control of known detrimental contaminants such as conductivity, chloride, and sulfate concentrations within the guidelines of the Boiling Water Reactor Vessel and Internals Project BWRVIP-190, Revision 1 (EPRI-3002002623) to minimize loss of material or cracking. It should be noted that NUREG-2191 currently references EPRI 1016579, which is the BWRVIP-190 Revision 0. PBAPS has implemented EPRI 3002002623, which is the BWRVIP-190 Revision 1. As stated in NUREG-2221, “the staff finds BWRVIP-190, Revision 1... acceptable to cite without exception”.

The Water Chemistry program consists of monitoring and controlling the chemical environments of those systems that are exposed to reactor water, steam, condensate, feedwater, control rod drive water, demineralized water, torus water, and spent fuel pool water, such that aging effects of system components are minimized in accordance with BWRVIP-190. Sampling frequencies, action limits for each control parameter, and corrective actions are defined in specific procedures. Conditions that do not meet acceptance criteria are evaluated in accordance with the corrective action program.

Major component types managed by this program include the reactor vessel, reactor internals, piping, piping elements, heat exchangers, and tanks. Reactor water, condensate, control rod drive water, feedwater, demineralized water storage tank water, torus water, spent fuel pool water, condensate storage tank water, and refueling water storage tank water are classified as treated water for aging management.

The Water Chemistry program is also credited for mitigating loss of material and cracking for components exposed to sodium pentaborate, and auxiliary steam environments. The Standby Liquid Control (SLC) System contains a demineralized water and sodium pentaborate solution controlled in accordance with plant procedures and Technical Specifications. The managing of aging effects on SLC system components subject to the sodium pentaborate environment relies on monitoring and control of SLC poison storage tank makeup water chemistry. The makeup water from the demineralized water storage tank is monitored in lieu of the sodium pentaborate solution in the SLC poison storage tank, because the sodium pentaborate would mask the chemistry parameters monitored. The chloride content of the sodium pentaborate powder is certified by the manufacturer to have low levels of chloride contamination. The Auxiliary Steam System contains boiler treated water and auxiliary steam that is controlled in accordance with plant procedures and industry standards.

Industry experience has shown that water chemistry programs may not be effective in low flow or stagnant flow areas of plant systems. The Water

Chemistry program does not provide for detection of aging effects. However, components located in such areas will receive a one-time inspection prior to the second period of extended operation. This inspection will be performed as part of the One-Time Inspection (B.2.1.21) program. This program includes provisions specified by NUREG-2191 for the verification of proper chemistry control and aging management.

NUREG-2191 Consistency

The Water Chemistry aging management program is consistent with the ten elements of aging management program XI.M2, "Water Chemistry" specified in NUREG-2191, with the following exception:

Exceptions to NUREG-2191

1. The NUREG-2191 Chapter XI.M2, Water Chemistry aging management program monitors parameters of various plant water systems in accordance with the guidelines contained in the BWRVIP-190. The scope of the Peach Bottom Water Chemistry aging management program includes treated water within the Auxiliary Steam System which does not fall under the scope of BWRVIP-190. **Program Element Affected: Scope of Program (Element 1)**

Justification for Exception:

There is currently no NUREG-2191 program that addresses water chemistry for treated water within the Auxiliary Steam System. The Peach Bottom Water Chemistry program includes chemistry controls for the Auxiliary Steam System. The critical chemistry parameters for the Auxiliary Steam System are monitored in accordance with industry standards, specifically ASME standard ISBN-0-7918-1204-9, “Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers.” A review of plant operating experience indicates that the chemistry controls for this environment are adequate to mitigate aging. The effectiveness of this portion of the Water Chemistry program will be verified by a one-time inspection of selected Auxiliary Steam System components as part of the One-Time Inspection (B.2.1.21) program.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Water Chemistry program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing water chemistry aging management activities in support of preparing the license renewal application for second license renewal. The specific activities reviewed were the Reactor Coolant System

Chemistry Activities, the Demineralized Water and Condensate/Refueling Water Storage Tank Chemistry Activities, the Torus Water Chemistry Activities, the Fuel Pool Chemistry Activities, and the Heat Exchanger Inspection Activities, as described in UFSAR Sections Q.1.2, Q.1.4. Q.1.5, Q.1.6, and Q.2.12. The purpose of the aging management program effectiveness review was to verify that the intent of the existing aging management program, to control water chemistry to manage loss of material, cracking, and reduction of heat transfer aging effects for components exposed to these environments, is being effectively implemented in the first period of extended operation.

The aging management program effectiveness review was comprised of a review of plant water chemistry data documented during the period from 2003 to 2016, review of heat exchanger inspection results during this same period, and review of issues documented in the corrective action program relevant to maintaining water chemistry within the required parameters and material condition of applicable heat exchangers. The review found that water chemistry parameters are frequently monitored and verified to be within the expected limits, and when these limits are exceeded an issue report is generated in the corrective action program. These issues are evaluated to identify the cause of the condition, and perform follow-up actions as required to restore the water chemistry to the appropriate levels and establish long-term actions, if necessary. Additionally, the review found that heat exchanger inspections were performed as required and as-found condition was documented. When unexpected material conditions were identified they were evaluated in the corrective action program. Further, during this time period, EPRI and BWRVIP-190 industry guidance was revised to reflect the most recent industry best practices, research, and operating experience. The Water Chemistry program was revised to incorporate the 2014 revision to BWRVIP-190, to ensure that best practices are adopted. Therefore, the aging management program effectiveness review determined that the program is being implemented in accordance with UFSAR Sections Q.1.2, Q.1.4, Q.1.5, Q.1.6, and Q.2.12.

This operating experience provides objective evidence that water chemistry management activities are effectively monitored and adjusted to manage the loss of material, cracking, and reduction of heat transfer aging effects to assure that in scope SSCs will be able to continue to perform their intended functions. In addition, this operating experience provides objective evidence that industry operating experience is incorporated into aging management programs, and that these aging management activities are appropriate to be performed during the second period of extended operation.

2. During a refueling outage in 2010, reactor coolant EPRI Action Level 1 limits were exceeded for conductivity, chloride, and sulfate concentration. The issue was entered into the corrective action program. The cause was determined to be a leak in a RHR heat exchanger, which was placed in service to support the shutdown cooling mode of operation. Actions were taken to isolate the heat exchanger and to ensure that the reactor water cleanup system remained in service until the action level had been exited. The chemistry parameters were restored below the action level threshold within 41 hours, well within the guideline of 96 hours. A root cause analysis was performed, and

corrective actions included repair of the heat exchanger, evaluation of fuel warranty implications, procedural changes, review of decision making processes, and training of applicable work groups.

This example provides objective evidence that water chemistry parameters are monitored, and corrective actions are taken to ensure that industry guidelines and station procedural requirements are maintained.

3. In 2016, a focused area self-assessment (FASA) was performed to review the Reactor Vessel and Internals program to review program compliance in several areas including programmatic, implementation, and infrastructure. The FASA compared the site programs, procedures, and processes against the BWRVIP guidelines in various functional areas, one of which was water chemistry control. The objective was to confirm that the BWR Chemistry Control Guidelines and Mitigation Policies are properly implemented for the Reactor Vessel and Internals components, and to determine if there are deviations or gaps between the guidelines and site implementation. The FASA concluded that the BWRVIP-190 guidelines have been accurately incorporated into site and corporate procedures, that hydrogen water chemistry mitigation exists for critical components, and that the analytical model for determining proper hydrogen water chemistry flow rates is being utilized to ensure proper mitigation. A recommendation was made to improve the documentation of these model runs.

This example provides objective evidence that the Water Chemistry program includes periodic assessments which are effective in ensuring the program objectives are being met and opportunities for improvements are implemented.

4. The refueling water storage tank (RWST) was not in scope for the first license renewal. A plant modification was performed for extended power uprate, which was implemented and changed the plant licensing basis in 2014 to credit the RWST for the Appendix R and ATWS events. Therefore, the RWST was added to the scope of license renewal under the provision of 10 CFR 54.37(b) as a newly identified SSC, and the RWST water chemistry is now monitored as an aging management activity. In 2016, silica levels in the RWST exceeded the goal value. The issue was entered into the corrective action program and evaluated. This condition was determined to be expected, since it was related to the ISFSI campaign where the spent fuel pool water was let down to the RWST for level control. Water chemistry parameters were monitored throughout the ISFSI campaign, with an action to polish the RWST water upon completion.

This example provides objective evidence that plant modifications are evaluated for license renewal scope impact and aging management applicability, and that aging management programs are updated accordingly. Additionally, water chemistry parameters are monitored, and conditions that exceed established limits are addressed as appropriate

5. The Unit 2 torus water was determined to be above the limit for total organic carbon (TOC) in 2013. Further investigation determined that the elevated TOC level was associated with the recoating of the torus, which was performed during the previous refueling outage. Additionally, the condition was

not recognized when it occurred. This issue was entered into the corrective action program for further evaluation and follow-up action. Confirmatory chemical analyses confirmed that the predominant parameters were the same as the curing agent used in the torus coating. Additional corrective actions included restoring the torus water chemistry to acceptable levels, development of an automatic alert flag to immediately identify out-of-spec chemistry conditions, re-verification of water chemistry monitoring and trending practices, identification of personnel responsibility, assessment of the process for approving chemicals for use, and communication within Exelon and to the industry of the findings and lessons learned.

This example provides objective evidence that the corrective action program is effectively used to evaluate and address technical and programmatic issues to strengthen aging management programs, and that operating experience is shared with the industry.

The operating experience relative to the Water Chemistry program did not identify an adverse trend in performance. The monitoring methods being implemented by the program have been proven effective in managing aging effects including cracking, loss of material, and reduction of heat transfer. Appropriate guidance for evaluation and corrective action is provided for locations where degradation is found. Periodic assessments of the Water Chemistry program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Water Chemistry program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing Water Chemistry program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.3 Reactor Head Closure Stud Bolting

Program Description

The Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that includes ASME Code, Section XI examinations of reactor head closure studs, flange threads, and associated nuts, washers, and bushings to manage cracking and loss of material. The Reactor Head Closure Stud Bolting program manages these aging effects in an air-indoor uncontrolled environment. The program is based on the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures recommended within NRC Regulatory Guide (RG) 1.65 Revision 1, “Materials and Inspection for Reactor Vessel Closure Studs.”

The Reactor Head Closure Stud Bolting program implements ASME Code, Section XI inspection requirements through the ISI Program plan. The current ISI Program plan for the fourth 10-year inspection interval (November 5, 2008 through December 31, 2018) is based on the 2001 ASME Code, Section XI, including 2003 addenda. The future 120-month inspection intervals will incorporate the requirements specified in the version of the ASME Code referenced in 10 CFR 50.55a 12 months before the start of the inspection interval.

The program uses visual and volumetric examinations in accordance with the general requirements of ASME Code, Section XI, Subsection IWA-2000 to monitor for cracking, loss of material, and coolant leakage. The extent and schedule for examining and testing the reactor head closure stud bolting components is as specified in Table IWB-2500-1 for B-G-1 components, “Pressure Retaining Bolting Greater than 2 Inches in Diameter.” The studs and flange threads receive a volumetric examination, and the surfaces of nuts, washers, and bushings are inspected using VT-1 examination. The reactor vessel flange connection is within the ASME Code Class 1 pressure-retaining boundary that receives a visual VT-2 examination per Exam Category B-P during the system leakage test that is performed during each refueling outage.

Indications and relevant degraded conditions detected during examinations are entered into the corrective action program and evaluated in accordance with ASME Code, Section XI, Subsection IWB-3100 for Class 1 components by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500. Flaw indications or relevant degraded conditions are evaluated in accordance with IWB-3515 or IWB-3517 as indicated in Table IWB-2500-1 and Table 3410-1 of ASME Code, Section XI.

The reactor head closure studs are fabricated from ASME SA-540 Grade B23 or B24 alloy steel. The installed Unit 2 and Unit 3 studs, nuts, and washers are fabricated with material that may have ultimate tensile strength greater than or equal to 170 ksi. The Reactor Head Closure Stud Bolting program includes the other preventive measures described in RG 1.65, Revision 1 to prevent cracking. The reactor head closure studs, nuts, and washers were coated with an acceptable phosphate surface treatment to inhibit corrosion. In addition, a stable lubricant that does not contain molybdenum disulfide is applied to the studs, nuts, and washers prior to reactor vessel head re-installation.

NUREG-2191 Consistency

The Reactor Head Closure Stud Bolting aging management program is consistent with the ten elements of aging management program XI.M3, "Reactor Head Closure Stud Bolting" specified in NUREG-2191 with the following exceptions:

Exceptions to NUREG-2191

1. NUREG-2191 recommends, as a preventive measure that can reduce the potential for SSC, that the material used for existing closure studs have an ultimate tensile strength less than 170 ksi (1172 MPa). Certified Material Test Reports (CMTRs) for the materials used for fabrication of the existing reactor head closure studs and nuts installed on Units 2 and 3 include test results indicating that the studs may have ultimate tensile strength greater than or equal to 170 ksi. **Program Element Affected: Preventive Actions (Element 2)**

Justification for Exception

The reactor head closure studs and nuts are fabricated from SA-540 Grade B23 or B24 alloy steel, both of which require a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi. The reactor vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 edition with Winter 1965 Addenda. The design requirement for this bolting material is for the average Charpy V impact energy to be greater than 30 ft-lbs. The materials used to fabricate all installed stud bolting components meet this design requirement.

The CMTR data for the installed studs and nuts includes several sets of test results that include ultimate tensile strength and Charpy V impact energy for each heat used to fabricate the studs. Only 12 of 89 ultimate tensile strength test results reported on the CMTRs for the heats used for the Units 2 and 3 studs and nuts are greater than or equal to 170 ksi. Since the CMTRs include some test results that indicate ultimate tensile strength greater than or equal to 170 ksi, it is concluded that these components may have ultimate tensile strength greater than or equal to 170 ksi. The average of all the ultimate tensile strength test results for the heats used for Units 2 and 3 studs and nuts is 162 ksi. The CMTR data indicates that the installed stud bolting components have ultimate tensile strength that is at most marginally greater than NUREG-2191 criteria for ultimate tensile strength.

All other preventive measures listed in NUREG-2191 Chapter XI.M3, Reactor Head Closure Stud Bolting that reduce the potential for cracking are met.

- Metal-plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement;
- A phosphate surface treatment was applied to the studs, nuts, and washers during fabrication to inhibit corrosion;

- An approved stable lubricant is applied to the studs, nuts, and washers whenever the reactor head is installed. The lubricant used does not contain molybdenum disulfide which has been shown to be a potential contributor to SCC.

The aging management review identified the stud bolting material as “High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater”. This resulted in identifying cracking as an aging effect requiring management. The volumetric examination method required for stud inspection per ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1 is appropriate to identify cracking. There have been no recordable cracking indications identified by ISI program examinations of reactor head closure components during PBAPS operating history, indicating that the installed bolting components are in excellent material condition, have an excellent operating performance history, and that the current program has been effective to manage cracking. The Reactor Head Closure Stud Bolting aging management program will continue to include volumetric examination per Table IWB-2500-1, Exam Category B-G-1, and therefore will be effective in managing cracking during the second period of extended operation.

2. NUREG-2191 recommends, as a corrective action that can reduce the potential for SSC, that the maximum measured yield strength of replacement material should be limited as recommended in RG 1.65, Revision 1. RG 1.65, Revision 1 specifies that the material used for closure studs and nuts have measured yield strength less than 150 ksi (1034 MPa). Certified Material Test Reports (CMTRs) for the materials used for fabrication of the potential replacement reactor head closure stud and nut in the warehouse include test results with measured yield strength greater than or equal to 150 ksi. **Program Element Affected: Corrective Actions (Element 7)**

Justification for Exception

The potential replacement reactor head closure stud in the warehouse is fabricated from SA-540 Grade B24 alloy steel and the nut is fabricated from SA-540 Grade B23 alloy steel; both of which require a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi. The reactor vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 edition with Winter 1965 Addenda. The design requirement for this bolting material is for the average Charpy V impact energy to be greater than 30 ft-lbs. The materials used to fabricate the potential replacement stud and nut in the warehouse meet this design requirement. These components were purchased as potential replacements in 1972.

The measured yield strength test results on the CMTRs for the potential replacement stud and nut indicate that the measured yield strength for the stud and nut are greater than or equal to 150 ksi. The average of all the measured yield strength test results for the stud is 156 ksi and for the nut is 155 ksi. The CMTR data indicates that the potential replacement stud and nut have measured yield strength that is at most marginally greater than NUREG-2191 criteria.

All other preventive measures listed in NUREG-2191 Chapter XI.M3, Reactor Head Closure Stud Bolting that reduce the potential for cracking are met.

- Metal-plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement;
- A phosphate surface treatment was applied to the studs, nuts, and washers during fabrication to inhibit corrosion;
- An approved stable lubricant is applied to the studs, nuts, and washers whenever the reactor head is installed. The lubricant used does not contain molybdenum disulfide which has been shown to be a potential contributor to SCC.

The purchasing requirements for RPV head stud bolting components include specification that future purchases of these components for Units 2 and 3 have measured yield strength less than 150 ksi as reported on CMTRs, consistent with RG 1.65, Revision 1.

Since the studs and nuts installed on Units 2 and 3 are also fabricated from SA-540 Grade B23 or B24 alloy steel having measured yield strength marginally above 150 ksi, the aging management review identified the stud bolting material as "High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater". This resulted in identifying cracking as an aging effect requiring management. The volumetric examination method in place for stud inspection per ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1 is appropriate to identify cracking. There have been no recordable cracking indications identified by ISI program examinations of reactor head closure bolting components during PBAPS operating history, indicating that the current program has been effective to manage cracking. The Reactor Head Closure Stud Bolting program will continue to include volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1, and therefore will continue to be effective in managing cracking during the second period of extended operation.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Head Closure Stud Bolting program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management activities for reactor head closure stud bolting components in support of preparing the license renewal application for second license renewal. Inspections of reactor head closure stud bolting components are periodically performed as part of the Inservice Inspection (ISI) Program as described in UFSAR Section Q.1.8. The purpose of the aging

management program effectiveness review was to verify the intent of the existing aging management program, which is to manage cracking and loss of material of reactor head closure bolting components, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of inspection records during the fourth 10-year ISI inspection interval (November 2008 through December 2018) and pertinent issues found in the corrective action program, searching for age-related degradation of in scope SSC's. Information was collected from 2001 to 2016.

During this effectiveness review, examination reports for Unit 3 RPV head stud bushings 1-46 in 2011, and examination reports for flange threads 47-92 in 2015, could not be located. These examinations were recorded as complete in the ISI Program database. This issue was entered into the corrective action program. Because the examination reports could not be located, the inspection of RPV head stud bushings 1-46 was rescheduled and performed during the 2017 refueling outage, thereby ensuring that this required examination of the fourth 10-year ISI interval, covering the period from 2008 to 2018, was met. The inspection of flange threads 47-92 was not performed due to NRC approval of a relief request that has since eliminated the need to perform these inspections for the remainder of the current fourth 10-year ISI interval (Reference: NRC Relief Request Approval, ADAMS Accession No. ML17170A013). The ISI Program database software that is currently in use addresses the cause of this issue and precludes recurrence by requiring all the necessary records associated with the completed examination to be entered into the database before the database statuses the examination as complete. An extent of condition review was also performed that determined there are no other similar issues.

The review identified that all other inspections of reactor head closure stud bolting components are being performed in accordance with ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1 requirements as further described in Operating Experience examples 2 and 3 below. The review did not identify age-related degradation of in scope components. The review also concluded that the reactor head closure stud bolting components are in excellent condition on Units 2 and 3.

This operating experience provides objective evidence that the current Inservice Inspection (ISI) Program is being effectively implemented to manage aging effects of reactor head closure stud bolting components in accordance with ASME Section XI requirements, and that continued implementation of the Reactor Head Closure Stud Bolting aging management program will assure that the reactor head closure stud bolting components will continue to perform their intended functions during the second period of extended operation.

2. During the Unit 2 refueling outage in 2010, reactor head closure studs and flange threads 1 through 46 were examined using the volumetric test (UT) examination method. Reactor head closure nuts, washers and bushings 1 through 46 were examined using the VT-1 method. There were no recordable indications.

During the Unit 2 refueling outage in 2016, reactor head closure studs and flange threads 47 through 92 were examined using the UT examination method. Reactor head closure nuts, washers, and bushings 47 through 92 were examined using the VT-1 method. There were no recordable indications.

This example demonstrates that the reactor head closure stud bolting components were inspected in accordance with ASME Code Section XI requirements using examination techniques that would identify cracking and loss of material during the fourth 10-year ISI interval. The reactor head closure stud bolting components were verified to be in excellent material condition.

3. During the Unit 3 refueling outage in 2011, reactor head closure studs, and flange threads 1 through 46 were examined using the UT examination method with no indications found. Reactor head closure nuts and washers 1 through 46 were examined using the VT-1 method. Washer set 11 was replaced due to nicks and raised metal on the washer surface that was identified during the VT-1 inspection. The condition was not age-related. There were no other recordable indications.

During the Unit 3 refueling outage in 2015, reactor head closure studs 47 through 92 were examined using the UT examination method. Reactor head closure nuts, washers, and bushings 47 through 92 were examined using the VT-1 method. There were no recordable indications. The Unit 3 RPV head stud bushings 1-46 were examined using the VT-1 method during the refueling outage in 2017. A Relief Request to ASME Code, Section XI requirements was approved in June 2017 that eliminated the need to perform UT examination of the flange threads for the remainder of the current fourth 10-year ISI interval.

This example demonstrates that the reactor head closure stud bolting components have been inspected in accordance with ASME Code Section XI requirements using examination techniques that would identify cracking and loss of material. The reactor head closure stud bolting components were verified to be in excellent material condition.

The operating experience relative to the Reactor Head Closure Stud Bolting program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Reactor Head Closure Stud Bolting program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Reactor Head Closure Stud Bolting program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing Reactor Head Closure Stud Bolting program provides reasonable assurance that the cracking and loss of material aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.4 BWR Vessel ID Attachment Welds

Program Description

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of reactor vessel internal attachment welds due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or cyclic loading in a reactor coolant environment. This program relies on augmented visual inservice examinations to detect cracking. The program substitutes the inspection and evaluation recommendations within BWRVIP-48-A for the requirements within ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2. The potential for cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) is mitigated by maintaining high water purity as described in the Water Chemistry (B.2.1.2) program. The scope of the program includes the attachment welds for the steam dryer support and hold down brackets, guide rod brackets, feedwater sparger brackets, jet pump riser braces, core spray piping brackets, and surveillance sample holder brackets.

Indications are evaluated consistent with ASME Code, Section XI, Subsections IWB-3500 and IWB-3600 and the additional guidance provided in BWRVIP-48-A. If flaws are found, the condition is entered into the corrective action program and the scope of the inspection is expanded in accordance with the guidance provided in BWRVIP-48-A. Repair and replacement procedures comply with the requirements of ASME Code, Section XI. If the flaw exceeds the requirements of IWB-3600, repair and replacement is performed consistent with the requirements of ASME Code, Section XI, Subsection IWA-4000.

NUREG-2191 Consistency

The BWR Vessel ID Attachment Welds aging management program is consistent with the ten elements of aging management program XI.M4, "BWR Vessel ID Attachment Welds" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Vessel ID Attachment Welds program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management activities for reactor vessel interior attachment welds in support of preparing the license renewal

application for second license renewal. The inspections of reactor vessel interior attachment welds are periodically performed as part of the Reactor Pressure Vessel and Internals ISI Program as described in UFSAR Section Q.2.7. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage cracking of reactor vessel internal attachment welds, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of inspection records during the third and fourth 10-year ISI inspection intervals (November 1997 through December 2018) and pertinent issues found in the corrective action program, searching for age-related degradation of the reactor vessel interior attachment welds.

The review identified that the inspections of reactor vessel interior attachment welds are being performed in accordance with BWRVIP-48-A as further described in Operating Experience examples 2 and 3 below. The review did not identify age-related degradation of in scope components. The review also concludes that the reactor vessel interior attachment welds are in excellent condition on Units 2 and 3.

This operating experience provides objective evidence that the current Reactor Pressure Vessel and Internals ISI Program is being effectively implemented to manage aging effects in accordance with BWRVIP-48-A guidance and that continued implementation of the BWR Vessel ID Attachment Welds aging management program will assure that the reactor vessel interior attachment welds will continue to perform their intended functions during the second period of extended operation.

2. During the fourth 10-year ISI interval between November 2008 and December 2018 examinations of the Unit 2 reactor vessel interior attachment welds for jet pump riser braces, core spray piping brackets, steam dryer support brackets, and feedwater sparger brackets were performed in 2012, 2014, and 2016 using the EVT-1 method. Examinations of three of the six Unit 2 surveillance sample holder bracket attachment welds were performed in 2014 using the VT-1 method. Both guide rod bracket attachment welds were examined in 2016 using the VT-3 method. No cracking indications were identified by any of the examinations. The remaining examinations of the attachment welds for the steam dryer hold down brackets and three of the six surveillance sample holder brackets that are required to be performed during the fourth 10-year ISI interval are scheduled to be performed in 2018.

During the fourth 10-year ISI interval, examinations of the Unit 3 reactor vessel interior attachment welds for jet pump riser braces, core spray piping brackets, steam dryer support brackets, and feedwater sparger brackets were performed in 2011 and 2015 using the EVT-1 method. Examinations of the Unit 3 guide rod bracket attachment welds were performed in 2011 and surveillance sample holder bracket attachment welds were examined in 2015 using the VT-1 method. Examinations of the Unit 3 steam dryer hold down bracket attachment welds were performed in 2017 using the VT-3 method. No cracking indications were identified by any of the examinations.

This example demonstrates how condition monitoring in accordance with BWRVIP-48-A inspection guidelines are used to manage cracking in reactor vessel internal attachment welds. The inspections have not detected cracking in any of the attachment welds. The lack of cracking indications in the attachment welds can be attributed to effective reactor coolant chemistry management, suitable design, and effective installation practices.

3. Examinations of steam dryer support bracket attachment welds on Unit 2 in 2004, 2012, and 2016 and on Unit 3 in 2011 identified minor wear and localized deformation on the brackets surfaces. The issues were entered into the corrective action program. Engineering evaluations concluded that the localized deformation was caused by handling of the dryers during installation and removal; the wear was caused by vibration of the dryers on the brackets; and that the conditions did not affect the attachment weld or the structural support function of the brackets. The evaluation of the Unit 2 steam dryer support bracket condition recommended re-inspection of the brackets in 2018.

This example demonstrates that the methods used to examine the reactor vessel internal attachment welds are effective in identifying minor degraded conditions that are entered into the corrective action program where they are effectively evaluated and dispositioned.

The operating experience relative to the BWR Vessel ID Attachment Welds program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Vessel ID Attachment Welds program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Vessel ID Attachment Welds program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing BWR Vessel ID Attachment Welds program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.5 BWR Stress Corrosion Cracking

Program Description

The BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages intergranular stress corrosion cracking (IGSCC) in piping and piping welds made of stainless steel and nickel based alloy that are 4 inches or larger in diameter in reactor coolant greater than 200 degrees F, regardless of code classification. The program implements the program delineated in NUREG-0313, Revision 2, and NRC Generic Letter (GL) 88-01 and its Supplement 1. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects. Stainless steel piping and piping welds in the reactor water cleanup system that are 4 inches or larger in nominal diameter, contain reactor coolant or treated water above 200 degrees F during power operation, and are outside of the second primary containment and reactor coolant pressure boundary isolation valve, are managed by the BWR Reactor Water Cleanup System (B.2.1.15) program.

Reactor coolant water chemistry is controlled and monitored in accordance with EPRI guidelines to maintain high water purity and reduce susceptibility to SCC or IGSCC as described in the Water Chemistry (B.2.1.2) program. Induction heating stress improvement was applied to reduce susceptibility to IGSCC and is credited for five Unit 3 welds that are within the scope of the program. Hydrogen water chemistry and noble metals chemical application have been implemented to further reduce susceptibility of the piping systems exposed to reactor coolant to SCC or IGSCC.

The program addresses the management of crack initiation and growth due to IGSCC in the piping, welds, and components through the implementation of the ISI program in accordance with ASME Code, Section XI. Inservice inspections, performed as augmented requirements of the Section XI ISI program, ensure that aging effects are identified and repaired before the loss of intended function of in scope components. The inspection frequency for welds classified in accordance with NRC GL 88-01 as IGSCC Category B through G is per the recommendations provided in the staff-approved BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules" for normal water chemistry conditions. Welds classified as IGSCC Category A may be subsumed into the Risk-Informed Inservice Inspection (RI-ISI) program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A, Final Report, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," December 1999, pending approved ASME Code relief request. In the event that such relief is not approved by NRC staff for future ISI intervals during the second period of extended operation, Category A welds would be examined per the extent and schedule defined by BWRVIP-75-A.

Inspection and flaw evaluation is conducted in accordance with the ISI program plan. If a flaw exceeds the applicable acceptance standards of IWB-3500, then the condition is entered into the corrective action program and an analytical evaluation may be performed in accordance with IWB-3600 to determine its acceptability for continued service without repair or replacement. Evaluations are performed using the applicable crack growth rate provided by ASME Code, Section XI. BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 also provide approved guidelines that can be used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels. In accordance with NRC GL 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation.

The guidance for replacement, weld overlay repair, and stress improvement is provided in several industry documents, including NRC GL 88-01, NUREG-0313, Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved code cases.

NUREG-2191 Consistency

The BWR Stress Corrosion Cracking aging management program is consistent with the ten elements of aging management program XI.M7, "BWR Stress Corrosion Cracking" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Stress Corrosion Cracking program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the augmented ISI program in place to implement the PBAPS response to NRC GL 88-01 in support of preparing the license renewal application for second license renewal. This augmented ISI program is part of the first license renewal Inservice Inspection (ISI) Program described in UFSAR Section Q.1.8. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage cracking by performing ISI on IGSCC susceptible welds, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of an overall review of PBAPS actions related to NRC GL 88-01, review of inspection records during the fourth 10-year ISI inspection interval (November 2008 through December 2018), and pertinent issues found in the corrective action program from 2001 to 2016, searching for age-related degradation of piping and welds within the scope of the BWR Stress Corrosion Cracking program.

The review identified that inspections of piping welds within the scope of the BWR Stress Corrosion Cracking program are being performed in accordance with PBAPS commitments in response to NRC GL 88-01 as further described in Operating Experience examples 2 and 3 below. The review identified that inspections performed within the program are effective at identifying age-related degradation of in scope components. Age-related issues were evaluated and corrected in accordance with ASME Code, Section XI and requirements delineated in NRC GL 88-01, resulting in effective implementation of this aging management program. The review also concludes that the piping welds within the scope of the BWR Stress Corrosion Cracking program are in excellent condition on Units 2 and 3.

This operating experience provides objective evidence that the current Inservice Inspection (ISI) Program is being effectively implemented to manage aging effects in accordance with the PBAPS commitments in response to NRC GL 88-01. Continued implementation of the BWR Stress Corrosion Cracking aging management program will assure that the piping welds within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. On Unit 2, during the fourth 10-year ISI inspection interval (November 2008 through December 2018), volumetric examinations are being performed on all 15 IGSCC Category D welds every six years and an examination was performed on one of the two IGSCC Category E welds. There are no IGSCC Category B, C, F, or G welds on Unit 2. Also, during this current interval, 16 IGSCC Category A welds were examined. No indications of cracking were identified. Examinations of the Category D and E welds were performed per the schedules within BWRVIP-75-A. Examinations of the Category A welds were performed per the Risk-Informed ISI program schedules.

This example demonstrates that the industry guidelines delineated in NRC GL 88-01, NUREG-0313, Revision 2, and BWRVIP-75-A continue to be effectively implemented to monitor the condition of welds within the scope of the program.

3. On Unit 3, during the fourth 10-year ISI inspection interval, (November 2008 through December 2018), volumetric examinations were performed on two of the five IGSCC Category C welds and an examination was performed on the one IGSCC Category E weld. There are no IGSCC Category B, D, F, or G welds on Unit 3. Also, during this current interval, 22 IGSCC Category A welds were examined. No indications of cracking were identified. Examinations of the Category C and E welds were performed per the schedules within BWRVIP-75-A. Examinations of the Category A welds were performed per the Risk-Informed ISI program schedules.

This example demonstrates that the industry guidelines delineated in NRC GL 88-01, NUREG-0313, Revision 2, and BWRVIP-75-A continue to be effectively implemented to monitor the condition of welds within the scope of the program.

The operating experience relative to the BWR Stress Corrosion Cracking program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Stress Corrosion Cracking program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Stress Corrosion Cracking program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing BWR Stress Corrosion Cracking program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.6 BWR Penetrations

Program Description

The BWR Penetrations aging management program is an existing condition monitoring program that manages the aging effect of cracking due to cyclic loading or stress corrosion cracking of the BWR instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH) penetrations, and the standby liquid control (SLC)/core plate differential pressure (dP) nozzle exposed to a reactor coolant environment. The program is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel penetration and nozzle welds. The examination categories include volumetric, surface, and visual examination methods.

In addition to the requirements of ASME Code, Section XI, Subsection IWB, the BWR Penetrations program incorporates the inspection and flaw evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines," and the recommendations for reactor water chemistry as described in the Water Chemistry (B.2.1.2) program.

The BWR Penetrations program monitors the effects of cracking due to cyclic loading, stress corrosion cracking (SCC), and intergranular stress corrosion cracking (IGSCC) by requiring inspections of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and SLC/core plate dP nozzle as part of the ISI program per the requirements of ASME Code, Section XI, Table IWB-2500-1, a relief request to use BWRVIP guidance in lieu of ASME Code requirements, and BWRVIP reports. A description of the ISI program, including the controlling edition of ASME Code, Section XI, is provided in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program. During each refueling outage, a visual inspection (VT-2) of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and SLC/core plate dP nozzle is performed during the reactor coolant pressure boundary system leakage test. Abnormal or unexpected findings are entered into the corrective action program for evaluation and resolution.

When the reactor pressure vessel lower plenum area is accessible during normal reactor refueling activities, visual inspections are performed to the extent practical per BWRVIP-47-A guidelines. Inspections are performed in accordance with the guidelines of BWRVIP-49-A for the instrument penetrations, BWRVIP-47-A for the CRD housing and ICMH housing penetrations, and BWRVIP-27-A for the SLC/core plate dP nozzle. The guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A provide information on the type of penetrations, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation.

NUREG-2191 Consistency

The BWR Penetrations aging management program is consistent with the ten elements of aging management program XI.M8, "BWR Penetrations", specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Penetrations program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed of the existing aging management activities performed of the BWR vessel penetrations and nozzles in the scope of the BWR Penetrations program in support of preparing the license renewal application for second license renewal. Inspections of BWR vessel penetrations and nozzles in the scope of the BWR Penetrations program are performed as part of the first period of extended operation Reactor Pressure Vessel and Internals ISI Program aging management program described in UFSAR Section Q.2.7. The purpose of the effectiveness review was to verify the intent of the existing aging management program, which is to identify and address indications of cracking or loss of pressure boundary during NDE inspections associated with BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate dP nozzle, is being effectively implemented in the first license renewal period of extended operation. The program effectiveness review was comprised of a review of NDE reports, surveillance tests, and issues in the corrective action program associated with BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate dP nozzle from 2003 to 2016.

This review revealed that no indications of cracking or loss of pressure boundary were identified during the NDE inspections associated with BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate dP nozzle on either unit. The performance of the NDE inspections has resulted in the effective implementation of this aging management program. The program effectiveness review also verified the recommendations of BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49-A are being implemented as documented in UFSAR Section Q.2.7.

This operating experience provides objective evidence that the results demonstrate the inspection activities and the corrective action program effectively manage the aging effect of cracking in BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate dP nozzle to assure that these components will be able to continue to perform their intended functions during the second period of extended operation.

2. During the Unit 2 refueling outages in 2002, 2006, 2008, and 2010 and the Unit 3 refueling outages in 1999, 2003, 2005, 2007, and 2009, the baseline inspections of the lower plenum components that were recommended by BWRVIP-47-A were completed with no recordable indications identified. The alignment pin to core plate welds (FS/GT ARPIN-1) integrity was confirmed by either a VT-3 visual inspection or by the removal and installation of the fuel support casting. Control rod drive tube sleeve to alignment pin lug welds (CRGT-1) were inspected using VT-3 method. Control rod drive guide tube body to sleeve welds (CRGT-2) and guide tube base to body welds (CRGT-3) were inspected using EVT-1 method. No cracking or other material condition issues were identified during these baseline inspections; therefore the required acceptance criteria was met. Periodic re-inspection of these components is not currently required by BWRVIP-47-A.

This example provides objective evidence that the baseline inspections required by BWRVIP-47-A were implemented using the methods recommended for identifying cracking per the required inspection schedule.

3. During the Unit 2 refueling outage in 2008 and the Unit 3 refueling outage in 2011, the SLC/core plate dP nozzle to reactor pressure vessel weld was inspected using the UT method as required by ASME Section XI Table IWB-2500-1 and recommended by BWRVIP-27-A. Re-inspection is required once each 10-year ISI inspection interval. During the Unit 2 refueling outage in 2010 and the Unit 3 refueling outage in 2011, the SLC/core plate dP nozzle to safe end weld was inspected using the UT method as recommended by BWRVIP-27-A. Re-inspection is recommended every 10 years. No cracking or other material condition issues were identified during these inspections; therefore the required acceptance criteria was met.

This example provides objective evidence that the inspections required by BWRVIP-27-A are being implemented using the methods recommended for identifying cracking. Future inspections are scheduled as required by BWRVIP-27-A.

4. For both units, a reactor coolant pressure boundary system leakage test is performed each refueling outage. During this system leakage test, the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate dP nozzle were inspected using VT-2 method as recommended by BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A, respectively. No leakage from these components has been identified on either Unit 2 or Unit 3; therefore the required acceptance criteria was met.

This example provides objective evidence that the BWR Penetrations program includes use of visual examination techniques per applicable BWRVIP Reports and ASME Code, Section XI requirements to verify that there has been no loss of pressure boundary function for the components within the scope of the program.

The operating experience relative to the BWR Penetrations program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Penetrations program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Penetrations program will effectively manage the effects of aging, and initiate corrective actions prior to failure or loss of intended function during the second period of extended operation.

Conclusion

The existing BWR Penetrations program provides reasonable assurance that the aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.7 BWR Vessel Internals

Program Description

The BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents, and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including martensitic stainless steel (not installed in PBAPS reactor vessel internals), cast stainless steel and associated welds)

The BWR Vessel Internals aging management program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation. The program 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.2.1.2) program.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload for core plate rim hold-down bolts and jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity.

The program utilizes the following BWRVIP guidelines for inspection, evaluation, and repair recommendations for the components listed. If a new or revised BWRVIP guideline approves a less conservative requirement than the staff-approved version, the more restrictive requirement is followed until the staff approves the new or revised guideline.

Core Shroud: Inspections and flaw evaluations are performed in accordance with BWRVIP-76-R1-A. The repair design criteria in BWRVIP-02-A would be utilized in preparing a repair plan for the core shroud.

Core Plate: The BWRVIP recommendation to document deviation from BWRVIP-25 inspection guidelines of the core plate rim hold-down bolts is currently being implemented for PBAPS. The BWRVIP recognizes that it is not possible to implement meaningful inspections using the inspection methods recommended in BWRVIP-25. The BWRVIP is in the process of developing revised guidance. A BWRVIP deviation disposition is in place until revised BWRVIP guidance, or some other NRC-approved solution is implemented. The program is enhanced to require installation of core plate wedges prior to entering the second period of extended operation, or submittal of an inspection plan for the core plate rim hold-down bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation. The installation of core plate wedges would eliminate the need to inspect the core plate rim hold-down bolts. The repair design criteria in BWRVIP-50-A would be utilized in preparing a repair plan for the core plate.

Core Spray: Inspections and evaluations are performed in accordance with BWRVIP-18-R2-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. The repair design criteria in BWRVIP-52-A would be utilized in preparing a repair plan for the core shroud support.

Jet Pump Assembly: Inspections and evaluations are performed in accordance with BWRVIP-41, Revision 3 and BWRVIP-138-R1-A. The repair design criteria in BWRVIP-51-A would be used in preparing a repair plan for jet pump components.

LPCI Coupling: PBAPS Unit 2 and 3 reactor vessel internals do not include a LPCI coupling therefore Inspections, flaw evaluations, and repairs performed in accordance with BWRVIP-42-A and BWRVIP-56-A do not apply.

Top Guide: Inspections and evaluations are performed in accordance with BWRVIP-26-A and BWRVIP-183. The repair design criteria in BWRVIP-50-A would be utilized in preparing a repair plan for the top guide. PBAPS Units 2 and 3 are committed to the inspection of guide grid beams in accordance with BWRVIP-183. Ten percent of the grids beam cells containing control rod blades are inspected every 12 years, with at least five percent inspected within six years of the start of the BWRVIP-183 inspection cycle. Inspections are performed using the EVT-1 method. The program also allows for inspections to be performed using UT once it becomes available. This inspection schedule will continue through the second period of extended operation.

Control Rod Drive Housing and Lower Plenum Components: Inspections and evaluations were 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.2.1.6) program. The repair design criteria in BWRVIP-55-A and BWRVIP-58-A would be utilized in preparing a repair plan for the control rod drive housings.

Steam Dryer: The PBAPS, Unit 2 and Unit 3 original equipment General Electric stream dryers were replaced with Westinghouse (Nordic style) steam dryers in 2014 and 2015, respectively. The replacement steam dryers were designed to have a minimum service life of 50 years, which encompasses the second period of extended operation for each unit.

The inspection guidance contained in BWRVIP-139-A does not address the Westinghouse (Nordic style) steam dryers installed in PBAPS Unit 2 and Unit 3 and therefore is not directly applicable. An inspection plan intended specifically for the Westinghouse (Nordic style) steam dryers was developed. The general principles and conclusions from BWRVIP-139-A, “BWR Vessel and Internals Project: Steam Dryer Inspection and Flaw Evaluation Guidelines”, BWRVIP-181-R1-A, “BWR Vessel and Internals Project: Steam Dryer Repair Design Criteria”, and Regulatory Guide 1.20, “Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing” were applied to the inspection plan described in WCAP-17635-P, “Peach Bottom Atomic Power Station Unit 2 and Unit 3 Replacement Steam Dryer Comprehensive Vibration Assessment Program (CVAP)”. WCAP-17635-P also includes manufacturer’s recommendations based on relevant operating experience.

The BWR Vessel Internals aging management program will be enhanced to perform periodic visual inspections of the Westinghouse (Nordic style) steam dryers to manage the aging effects of loss of material and cracking during the second period of operation.

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.

Evaluations of reactor vessel internal components determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement and cracking due to IASCC during the second period of extended operation. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components.

The program allows for deviation from BWRVIP examination recommendations based on the requirements of NEI-03-08. Any relief request from the requirements of ASME Code, Section XI is submitted to the NRC for approval in accordance with 10 CFR 50.55a.

Evaluation of indications or flaws identified by examination is conducted consistent with the applicable and approved BWRVIP guideline or ASME Code, Section XI, as appropriate for the affected component. Additional general guidelines per BWRVIP-14-A, BWRVIP-59-A, and BWRVIP-60-A are applied for 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 would be used for weld repairs of irradiated structural components.

BWRVIP License Renewal Applicant Action Items listed in the NRC Safety Evaluation Reports for BWRVIP reports are addressed in Appendix C.

NUREG-2191 Consistency

The BWR Vessel Internals aging management program will be consistent with the ten elements of aging management program XI.M9, "BWR Vessel Internals" specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. Inspection requirements in BWRVIP-139-A, "BWR Vessel and Internals Project Steam Dryer Inspection and Flaw Evaluation Guidelines", will not be used for steam dryer inspections because BWRVIP-139-A does not address the Westinghouse (Nordic style) steam dryers installed in PBAPS, Unit 2 and Unit 3. The original equipment General Electric steam dryers were replaced with new Westinghouse (Nordic style) dryers. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)**

Justification for Exception

The inspection requirements contained in BWRVIP-139-A do not address the Westinghouse (Nordic style) steam dryers installed in PBAPS, Unit 2 and Unit 3, and therefore are not applicable as described in the SER for BWRVIP-139-A, Limitation Number 1. The PBAPS, Unit 2 and Unit 3 original equipment General Electric stream dryers were replaced with Westinghouse (Nordic style) steam dryers in 2014 and 2015, respectively. The replacement steam dryers were designed to have a minimum service life of 50 years, which would encompass the second period of extended operation for each unit.

A post first cycle inspection of the Peach Bottom Unit 2 steam dryer was performed during the 2016 refueling outage. The inspection included successful visual inspection of all the inspection locations required by the Facility Operating License Condition 2.C(15)(f) for inspection of the replacement steam dryer, which included all the Table 1 locations. All observations were acceptable for the structural components and welds inspected. There were four non-structural construction welds found with cracks that were dispositioned acceptable as-is. The welds were not explicitly modeled or analyzed as part of the structural qualification of the dryer.

A post first cycle inspection of the Peach Bottom Unit 3 steam dryer was performed during the 2017 refueling outage. The inspection included successful visual inspection of all the inspection locations required by the Facility Operating License Condition 2.C(15)(f) for inspection of the replacement steam dryer, which included all the Table 1 locations. All observations were acceptable for the structural components and welds inspected. There were three non-structural construction welds found with cracks and one shim found with marks/wear that were dispositioned acceptable as-is. The welds were not explicitly modeled or analyzed as part of the structural qualification of the dryer.

An inspection plan intended specifically for the Westinghouse (Nordic style) steam dryers was developed. The BWR Vessel Internals aging management program will be enhanced to perform periodic visual inspections of the steam dryers to manage the aging effects of loss of material and cracking during the second period of operation.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Install core plate wedges no later than six months prior to the second period of extended operation, or before the end of the last refueling outage prior to the second period of extended operation, whichever occurs later; or, submit an inspection plan for the core plate rim hold-down bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation. **Program Elements Affected: Scope of Program (Element 1) and Parameters Monitored or Inspected (Element 3)**

2. Perform a VT-3 inspection of the jet pump inlet mixer and beam regions every refuel cycle after a fluence value of 1.3E+20 n/cm^2 (51 EFPY for Unit 2 and 63 EFPY for Unit 3) is reached at the jet pump holddown beam. **Program Elements Affected: Scope of Program (Element 1) and Parameters Monitored or Inspected (Element 3)**

3. Perform periodic visual inspections of the PBAPS Westinghouse (Nordic style) stainless steel steam dryers for the aging effects of loss of material and cracking at a frequency not exceeding 10 years, with the first inspections performed prior to the second period of extended operation, as described below.

The inspection guidance contained in BWRVIP-139-A does not address the Westinghouse (Nordic style) steam dryers installed in PBAPS Unit 2 and Unit 3 and therefore is not directly applicable. However, the general principles and conclusions from BWRVIP-139-A, "BWR Vessel and Internals Project: Steam Dryer Inspection and Flaw Evaluation Guidelines", BWRVIP-181-R1-A, "BWR Vessel and Internals Project: Steam Dryer Repair Design Criteria", and Regulatory Guide 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing" were applied to the inspection plan described in WCAP-17635-P, "Peach Bottom Atomic Power Station Unit 2 and Unit 3 Replacement Steam Dryer

Comprehensive Vibration Assessment Program (CVAP)". WCAP-17635-P also includes manufacturer's recommendations based on relevant operating experience. The scope of the inspection will include the items listed in Table 1 below.

The steam dryer inspections are based on the BWRVIP-139-A and WCAP-17635-P guidelines to identify loss of material (wear) and cracking using appropriate visual examination techniques (e.g., VT-1, VT-3) and qualified inspectors. The examination procedures identify the type and location of examination required for each dryer component as well as the reason for inspection. Acceptance criteria are consistent with BWRVIP-139-A and are described in procedures and work instructions. Flaws and abnormal indications identified will be entered into the corrective action program for engineering evaluation. The evaluations will consider increasing inspection frequency and scope as appropriate. Identified degradation left in the as found condition will be re-inspected as required by the engineering evaluation.

The repair design criteria contained in BWRVIP-181-R1-A and BWRVIP139-A will be used for any future repairs of the steam dryers. Repairs to the steam dryer will be inspected as specified in the repair design package. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)**

Table 1

Steam Dryer Inspection Program for the Second Period of Extended Operation in accordance with WCAP-17635-P

Inspection Location	Basis for Selection
1. Overall General Inspection of Outside of the Replacement Steam Dryer (to include outside of skirt)	Industry Operating Experience (BWRVIP 139-A, Section 1.1, Section 2.4.2) General Inspection for evidence of damage
2. Lifting Rods Top Ends (Unit 3 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
3. Hold Down Rods Top Ends (Unit 2 only)	Surfaces in contact during operation RG 1.20 Sec 2.3 (1)(b,d)
4. Support Ring Bottom Surface	RG 1.20 Sec 2.3 (1)(b,d) Surfaces in contact during operation
5. Outer hood (welds on outer surface)	Industry Operating Experience (BWRVIP 139-A, Section 1.1, Section 2.4.2) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)

6. Outer Ring Top Cage	Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)
7. Weld attachments between the brackets to the lifting rod and hold down rod and weld attachments between the brackets to top plate (lifting rod, Unit 3 only)	Industry Operating Experience (BWRVIP 139-A, Section 2.4.8) Higher stressed area identified in analysis (RG 1.20 Sec 2.3 (1)(e)) Inspection for evidence of IGSCC (weld not solution annealed)

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Vessel Internals program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management activities performed of the BWR vessel internals in support of preparing the license renewal application for second license renewal. Inspections of BWR vessel internals components are performed as part of the first period of extended operation Reactor Pressure Vessel and Internals ISI Program aging management program described in UFSAR Section Q.2.7. The purpose of the effectiveness review was to verify the intent of the existing aging management program, which is to identify and address indications of cracking and other aging effects associated with BWR reactor vessel internal components, is being effectively implemented in the first license renewal period of extended operation. The aging management program effectiveness review was comprised of a sampling review of component NDE examination reports, flaw evaluations, and issues in the corrective action program associated with BWR reactor vessel internals including; core spray sparger and piping, jet pump assemblies, core shroud support, core shroud, access hole covers, core plate and rim hold-down bolts, top guide, and steam dryer from 2003 to 2016.

The review identified that inspections are being performed in accordance with BWRVIP guidelines. This review also revealed that indications of cracking or other aging effects have been identified during NDE inspections, entered into the corrective action program, and evaluated for continue use or repair in accordance with the appropriate BWRVIP guidelines. The performance of the NDE inspections, flaw evaluations, and proper re-inspection and scope expansion has resulted in the effective implementation of this aging management program. The program effectiveness review also verified the recommendations of the associated BWRVIP documents are being implemented as documented in UFSAR Section Q.2.7.

This operating experience provides objective evidence that the current Reactor Vessel and Internals ISI Program is being effectively implemented during the first period of extended operation. Continued implementation of the BWR Vessel Internals aging management program inspection activities and the corrective action program will effectively manage the aging effects of cracking, loss of material, loss of preload, and loss of fracture toughness in BWR reactor vessel internal components to assure that these components will be able to continue to perform their intended functions during the second period of extended operation.

2. The Unit 2 and Unit 3 core shrouds are classified as Category C based on fabrication from Type 304 stainless steel with greater than six years of hot operation. Repair hardware is not installed on either the Unit 2 or Unit 3 core shroud.

Inspection of the Unit 2 core shroud was performed in 2012. Volumetric (UT) examinations of the horizontal welds H-1 thru H-7 and vertical welds V-1 thru V-8 were performed. Indications were identified on all horizontal welds (H-1 thru H-7) and on vertical weld V-3. The UT indications were entered into the corrective action program. Evaluation of the indications determined that all welds should be on a 10-year re-inspection interval, and therefore be inspected again in 2022. In addition to the UT examinations, EVT-1 visual inspections of the inside surface of the core shroud were performed to look for IASCC. The H-4 at 45 degrees, the intersection of H-4 and V5, and the intersection of H-4 and V-6 were inspected. No indications were identified during the visual inspection of the core shroud.

Inspection of the Unit 3 core shroud was performed in 2015. UT examinations of the horizontal welds H-1 thru H-7 and vertical welds V-3 thru V-6 were performed. Indications were identified on horizontal welds H1, H3, H4, and H5, and on vertical welds V-3 and V-6. The UT indications were entered into the corrective action program. Evaluation of the indications determined that all welds should be on a 10-year re-inspection interval, and therefore will be inspected again in 2025.

This example demonstrates that core shroud inspections are being performed in accordance with BWRVIP guidelines and that the shrouds on both units are being properly managed for aging. This example also demonstrates that the corrective action program is used effectively to identify and evaluate conditions adverse to quality.

3. The following Unit 2 jet pump (JP) inspections were performed in 2016:

- VT-1 of four slip joint clamps. Minor wear was detected on the JP05 slip joint clamp. The wear was evaluated as acceptable for continued use.
- VT-1 of 20 main wedges. New wedge rod wear was identified on JP03, JP13 and JP16 and evaluated as acceptable for continued use. The position of the wedges on JP12, JP14 and JP20 appeared to be lower than previously observed.
- VT-3 of three auxiliary wedges. Minor wear was identified on JP13 and JP18 auxiliary wedges and evaluated as acceptable for continued use.
- EVT-1 of 28 medium and high priority welds including riser pipe to riser brace welds, riser elbow to thermal sleeve, inlet and mixer connections,

riser elbow to riser pipe welds. A 1 5/8 inch flaw was noted on JP11/12 RS-1 weld and was evaluated as acceptable for one cycle with re-inspection next outage in 2018.

- EVT-1 of 60 diffuser to adapter welds. Indications were identified on 11 jet pump AD-3a/b backing rings. The largest indication was on JP03 with an indication length of approximately 3.6 inches. All indications were evaluated as acceptable for one cycle with re-inspection in 2018.
- EVT-1 of JP17 DF-2 weld from the outside to look for any visual indication of the flaw identified by a UT in 2006. Forty percent coverage of the outside diameter was achieved, all suspect areas were investigated, and no indications were identified.

The following Unit 3 jet pump inspections were performed in 2015:

- EVT-1 visual inspections were performed on medium and high priority welds. Two existing RS-1 flaws were examined with no change in length identified. No other indications were identified.
- VT-1 visual inspections were performed on two riser clamps and no indications were observed.
- VT-1 visual inspections were performed on 10 JP main wedges. No new wedge wear was identified; however, wedge rod wear was identified on JP11, JP12, JP15, and JP20. All previous wedge rod wear on JP09, JP16, JP17 and JP19 remained unchanged.
- VT-3 visual inspections were performed on two auxiliary wedges. No wear was identified on JP14. New wear on the JP09 auxiliary wedge and new wear into the belly band were noted. The auxiliary wedge was in the over-travel position. The condition was evaluated and accepted for continued use for one cycle.
- EVT-1 visual inspections were performed on the outside of JP02, JP09, JP10, JP13, JP14, JP17, JP18 and JP19 diffuser/ adapter welds (AD-1, AD-2, DF-1, DF-2, AD3a/b and DF-3). A previously identified indication on JP02 AD3b weld showed no change from 2005. A previously identified indication on JP10 AD3b weld showed a small change in length from 2005 and was evaluated as acceptable. No other indications were observed.
- UT volumetric examinations were performed on the inside of JP09, JP10, JP11, JP12 and JP18 diffuser/ adapter welds (AD-1, AD-2, DF-1, DF-2, AD3a/b and DF-3). Previously identified indications on JP12 and JP09 AD3b welds showed small changes in length from 2005 and were evaluated as acceptable. Two of three previous indications on JP18 AD3a weld showed no change from 2005. The third indication was not observed or could not be found. No other indications were observed.

This example demonstrates that inspections of jet pump welds, wedges, and repair components are being performed in accordance with BWRVIP guidelines and that those inspections are effective in identifying aging effects prior to loss of intended function. This example also demonstrates that the corrective action program is used effectively to identify and evaluate conditions adverse to quality and to monitor and trend the conditions.

4. The following Unit 2 core spray piping inspections were performed in 2016. EVT-1 visual inspections were performed on seven pipe welds. Re-examination of indications on the P3B1 weld identified no growth from 2014. Structural and leakage evaluations determined that the flaw was acceptable for one cycle. All other examinations identified no indications.

In 2013, the Unit 3 internal core spray piping from the N5A and N5B RPV nozzles to the core shroud entrance was replaced due to previously identified cracks. As a result of the installation of the replacement hardware, welds P3, P4a, P4b, P4c, P4d, P5, P6, P7, P8a, P8b, and hidden weld P9 were eliminated from each branch of each loop. Welds P1 and P2 were also eliminated from each loop. Clamps were installed on the core spray sparger pipes to structurally replace one S1 weld and two S2 welds at each of the four sparger T-box locations. In 2015, VT-1 and VT-3 examinations of entire core spray line, brackets, and clamps were performed after one cycle of operation. Visual examinations confirmed all repair hardware was in place and had not changed from the as-installed condition. No indications were identified.

This example demonstrates that inspections of core spray piping components are being performed in accordance with BWRVIP guidelines and that those inspections are effective in identifying cracking indications prior to loss of intended function. This example also demonstrates that the corrective action program is used effectively to evaluate conditions adverse to quality and to monitor and trend the condition, repair, or replace the affected component.

The operating experience relative to the BWR Vessel Internals program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Vessel Internals program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the BWR Vessel Internals program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced BWR Vessel Internals program will provide reasonable assurance that the aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide assurance that reactor coolant pressure boundary CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement meet the specified intended functions. The reactor coolant system ASME Code Class 1 CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The PBAPS ASME Section XI Inservice Inspection program that implements Subsection IWB requirements will be augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program which will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250 degrees Celsius (482 degrees Fahrenheit). PBAPS Unit 2 and Unit 3 do not have any Class 1 piping or fittings fabricated from CASS. The Class 1 reactor recirculation pump casings and covers are fabricated from CASS (CF-8M, CF-8, and CF-3).

The program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Revision 1). Components with the potential for significant thermal aging embrittlement will be managed through either, qualified visual inspections, such as enhanced visual examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation in accordance with ASME Code, Section XI. For pump casings, as an alternative to screening for significance of thermal aging embrittlement, no further actions are needed if a flaw tolerance evaluation performed as part of Code Case N-481 implementation is bounding for 80 years.

Inspections or evaluations are not required for components for which thermal aging embrittlement is not significant. In addition, screening for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement is not required, because the existing ASME Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies.

Reactor vessel internal components fabricated from CASS are not within the scope of this aging management program and are managed by the BWR Vessel Internals (B.2.1.7) program.

The program will provide for either enhanced visual inspections, qualified ultrasonic testing methodology, or flaw tolerance evaluations of susceptible components; it will not provide guidance on methods to mitigate thermal aging embrittlement. The flaw tolerance evaluation will be based on specific geometry and stress information to verify that the thermally-embrittled material has adequate toughness throughout the second period of extended operation.

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel program inspections, if required, will be based on ASME Code, Section XI, Table IWB-2412-1 and performed during each 10-year ISI interval. There are no ASME Class 2 components within this program, therefore, Table IWC-2412-1 does not apply. The PBAPS ASME Section XI program plans direct the inspection schedules and the extent of the inspections in the program planning documents as required to provide timely detection of flaws. Abnormal or unacceptable results identified are entered into the corrective action program for evaluation and resolution.

Flaws detected in reactor coolant pressure boundary ASME Code Class 1 CASS components are entered into the corrective action program and evaluated in accordance with the applicable procedures of ASME Code, Section XI. The ferrite content of the PBAPS Unit 2 and Unit 3 recirculation pump casings and covers are less than 20 percent therefore ASME Code, Section XI can be used for flaw evaluations. Repairs and replacements are performed in accordance with the ASME Section XI Code, which specify the requirements in IWA-4000, per the PBAPS ISI program.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program will be a condition monitoring program whose methods will effectively detect and monitor the applicable aging effects and the frequency will be adequate to prevent significant age-related degradation.

This new program will be implemented prior to the second period of extended operation.

NUREG-2191 Consistency

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program will be consistent with the ten elements of aging management program XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 1994, on Unit 2, the “A” reactor recirculation pump internal surfaces were inspected, and in 2002, the “B” reactor recirculation pump internal surfaces

were inspected. The visual inspections (VT-3) were performed during the replacement of the pump internals in accordance with ASME Code Section XI, Table IWB-2500-1, Item No. B12.20, Pump Casing, (B-L-A). No recordable indications were identified on either pump.

Although not related to management of thermal embrittlement of cast austenitic stainless steel, this example provides objective evidence that the ASME Section XI Inservice Inspection (ISI) program is effectively utilized to perform required opportunistic examinations on the reactor recirculation pump casing that are within the scope of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program.

2. In 2003, on Unit 3, the "A" reactor recirculation pump internal surfaces were inspected, and in 2007, the "B" reactor recirculation pump internal surfaces were inspected. The visual inspections (VT-3) were performed during the replacement of the pump internals in accordance with ASME Code Section XI, Table IWB-2500-1, Item No. B12.20, Pump Casing, (B-L-A). No recordable indications were identified on either pump.

Although not related to management of thermal embrittlement of cast austenitic stainless steel, this example provides objective evidence that the ASME Section XI Inservice Inspection (ISI) program is effectively utilized to perform required opportunistic examinations on the reactor recirculation pump casings that are within the scope of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program.

The operating experience relative to the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of fracture toughness. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will provide reasonable assurance that the identified effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.9 Flow-Accelerated Corrosion

Program Description

The Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion (FAC) in carbon steel heat exchanger components, piping and piping components exposed to reactor coolant, steam, and treated water environments. The program is based on commitments made in response to NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning," and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R4 for an effective FAC program.

CHECWORKS is used to predict component wear rates and remaining service life in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS model is also refined by importing actual volumetric inspection data thickness measurements and re-running the wear rate analysis. This improves the predictive capability of the model to ensure that intended functions are maintained. Additionally, the program utilizes industry operating experience, plant experience, and engineering judgment of plant engineers to determine inspection locations.

Changes made to the CHECWORKS model are done by a qualified FAC engineer. Each change is then independently reviewed and validated by a qualified FAC engineer. Evaluations documenting the calculation of wear, wear rate, remaining life, next scheduled inspection, and sample expansion are independently reviewed by a qualified FAC engineer.

The program also manages wall thinning caused by mechanisms other than FAC in carbon steel and stainless steel piping and piping components exposed to closed cycle cooling water, raw water, steam, and treated water in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating and trending inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

FAC inspections and inspections performed for wall thinning caused by mechanisms other than FAC that do not meet acceptance criteria are evaluated in accordance with the corrective action program.

NUREG-2191 Consistency

The Flow-Accelerated Corrosion aging management program will be consistent with the ten elements of aging management program XI.M17, "Flow-Accelerated Corrosion" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program element:

1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for the second period of extended operation. **Program Element Affected: Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Flow-Accelerated Corrosion program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed of the Flow Accelerated Corrosion Program as described in UFSAR Section Q.1.1 in support of preparing the license renewal application for second license renewal. The purpose of the effectiveness review was to verify the intent of the existing aging management program, which is to monitor the condition of piping susceptible to FAC induced wall thinning, is being effectively implemented during the first period of extended operation. Inspection results from the previous three refueling outages for both Units 2 and 3 were reviewed. Elements of the program that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection data, sample expansion criteria, repair/replacement criteria, and program document updates. The performance of these activities was determined to comply with the requirements of the program. The program effectiveness review also confirmed that the program is being implemented as described in UFSAR Section Q.1.1.

Operating experience within the corrective action program relative to Flow-Accelerated Corrosion program activities from 2001 through 2016 was reviewed. Included within this review was an assessment of the corrective action program in evaluating and correcting identified age-related issues. The review determined that flow-accelerated corrosion inspections are effective in identifying age-related degradation. Deficiencies identified during the performance of inspections were evaluated in the corrective action program. The performance of inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of this program.

In 2012 (Unit 2) and 2013 (Unit 3), pre-period of extended operation implementation of the Flow Accelerated Corrosion Program was assessed by the site aging management program owner as part of a site-wide, license renewal implementation assessment. As documented in the "Peach Bottom Atomic Power Station Flow Accelerated Corrosion Aging Management Program Results Binder", 16 representative FAC inspections were identified and reviewed associated with the Main Steam, Feedwater, Reactor Core Isolation Cooling, and High Pressure Coolant Injection systems. The assessment concluded that the inspection results were properly evaluated and that wear, wear rate, remaining life, and next scheduled inspection were determined in accordance with the requirements of the program. Additionally, the assessment did not identify any corrective action program issue reports related to license renewal implementation or aging that necessitated changes to the Flow Accelerated Corrosion Program. In January 2013, the results binder for the program was reviewed by the NRC during the 71003, "Post-Approval Site Inspection for License Renewal" inspection to ensure that program commitments were being properly implemented prior to entering the period of extended operation. No issues with the implementation of the Flow Accelerated Corrosion Program were identified by the NRC during the inspection.

In December 2014, the Flow Accelerated Corrosion Program was again reviewed by the NRC during the 71004, "Power Uprate" inspection. The purpose of the assessment was to address risk-significant concerns identified by the program which could be exacerbated by power uprate changes or evolutions. No NRC findings were identified.

This example provides objective evidence of aging management program effectiveness during the first period of extended operation, and provides objective evidence that the continued implementation of the program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the second period of extended operation.

2. During the Fall 2016 Unit 2 refueling outage, a saddle plate installed in 2004 to repair erosion in the main steam drain header to the condenser failed inspection. The inspection was performed as part of the EPC (Erosion in Piping and Components) program which was developed in response to plant-specific and industry operating experience with wall thinning due to mechanisms other than FAC. Five readings were below the minimum allowable thickness. The issue was entered into the corrective action program for evaluation. Based on the location and highly localized nature of the wall thinning condition, the cause was determined to most likely be liquid drop impingement. The drain header was repaired by installing an additional saddle plate on top of the pre-existing saddle plate. Based on a calculated material

loss rate, engineering determined the next scheduled inspection to be during the fall 2022 refueling outage.

Because of the failure history of the main steam drain header it was concluded that the design is inadequate to prevent erosion damage. The following additional actions are being taken:

- Engineering will evaluate the removal of two upstream restricting orifices which could eliminate the conditions that cause liquid drop impingement.
- Engineering will redesign the main steam drain header which would lessen the impacts of liquid drop impingement.

This example provides objective evidence that age-related inspection findings are entered into the corrective action program and appropriate corrective actions are taken to evaluate and correct deficiencies.

3. A periodic five-year Focused Area Self-Assessment (FASA) for the FAC Program was conducted in October 2014. The purpose of the FASA was to determine the effectiveness of the FAC Program by:

- Assessing the program to the inspection methodology of NRC IP-71004, “Power Uprate” and IP-49001, “Inspection of Erosion/Corrosion Monitoring Programs,”
- Reviewing program compliance against the requirements outlined in the FAC program implementing procedures, and
- Verifying the program incorporates industry best practices and that known problem areas from plant-specific and industry OE were selected for inspection during the upcoming refueling outage.

The FASA resulted in the identification of 11 program recommendations and one program strength. Activities were assigned to track resolution of the recommendations. Three program deficiencies were identified. Corrective action program issue reports were generated to capture and evaluate the identified program deficiencies in the corrective action program. All program recommendations and deficiencies were evaluated and required changes to the program were implemented.

This example provides objective evidence that the program manager critically self-assesses program performance and self-identifies actions that support continuous improvement.

4. Due to feedwater heater dump valve degradation, several dump lines from the feedwater heaters to the main condenser were experiencing more frequent flow than designed. Feedwater heater dump lines are considered non-susceptible to FAC and excluded from the scope of the program since they are infrequently used lines with a total operating and testing time that is less than two percent of the plant operating time. Because these lines were experiencing more frequent flow, an assessment was performed to determine the susceptibility of the lines to FAC. The assessment reviewed plant-specific

OE associated with unexpected dump line flow and developed a prioritized inspection plan to address potential FAC degradation in these lines. During the Fall 2016 Unit 2 refueling outage, the dump line from the 2BE002 feedwater heater was inspected. During the Fall 2017 Unit 3 refueling outage, the dump lines from the 3AE002 and 3AE004 feedwater heaters were inspected. All inspection results were satisfactory with little to no indication of wall thinning due to FAC.

This example provides objective evidence that plant-specific operating experience that potentially involves aging is evaluated and used to adjust the program as necessary.

5. Licensee Event Report (LER) 2015-002, "Improper Flow Accelerated Corrosion Model Results in 4-Inch Steam Line Failure and Manual Reactor Trip" identified an issue at the Davis-Besse Nuclear Power Station where two-phase flow resulted in the failure of the moisture separator/reheater second stage reheater vent piping elbow. The failed elbow was downstream of a restricting orifice. This orifice was modeled in the FAC CHECWORKS software model as having an opening of 3.0 inches in diameter when the actual opening was 0.859 inches. The incorrect orifice opening size caused the CHECWORKS software to incorrectly calculate the wear rate of the elbow. Because of this incorrectly calculated wear rate, no wall thickness measurements were ever performed directly on the failed elbow. An extent of condition review identified that 30 of the station's 70 orifice type components were incorrectly modeled.

This event was evaluated by the Peach Bottom FAC program owner as part of the OPEX process. The Peach Bottom CHECWORKS model was checked for correct modeling of all flow element components. The review identified several discrepancies in the model involving pipe and flow element configuration. A corrective action program issue report was generated and appropriate changes to CHECWORKS were made. There were no operability concerns identified as a result of these changes.

This example provides objective evidence that industry operating experience that involves aging is evaluated and used to adjust the program as necessary.

The operating experience relative to the Flow-Accelerated Corrosion program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including wall thinning. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Flow-Accelerated Corrosion program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Flow-Accelerated Corrosion program will effectively identify degradation prior to failure or loss of intended function during the second period of extended operation.

Conclusion

The enhanced Flow-Accelerated Corrosion program will provide reasonable assurance that the wall thinning aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.10 Bolting Integrity

Program Description

The Bolting Integrity aging management program is an existing condition monitoring program which manages aging for loss of preload, cracking, and loss of material of safety-related and nonsafety-related closure bolting on pressure-retaining components. The program utilizes recommendations and guidelines delineated in NUREG-1339, EPRI NP-5769, TR-1015336, and TR-1015337 for material selection, use of approved lubricants, proper torqueing, and leakage evaluations which are implemented during plant surveillance and maintenance activities.

In addition, the program manages aging of submerged mechanical bolting on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens.

The program activities provide for aging management of closure bolting on pressure-retaining components within the scope of second license renewal. The program includes periodic inspection, at least once per refueling cycle, of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material due to corrosion. The program also credits visual inspection of pressure-retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Section XI. In addition, the Bolting Integrity aging management program credits volumetric, surface, and visual inspections of ASME Section XI Class 1, 2, and 3 bolts, nuts, washers, and other associated bolting components performed in accordance with ASME Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The integrity of ASME and non-ASME pressure-retaining bolted joints which contain fluids such as water, oil, or steam is assessed by detection of visible leakage, evidence of past leakage, or other age-related degradation during walkdowns and maintenance activities. Conditions such as: degraded bolts, nuts and threads; active leakage; high noise levels; loose or missing bolts and nuts; evidence of past leakage; damaged insulation; discoloration; or other age-related degradation are entered into the corrective action program where the condition is evaluated. Resulting actions could include: operability evaluation, root cause determination, extent of condition evaluation, additional or more frequent inspections, and replacement. This could include, when practical, projections of identified corrosion or degradation rates until the next scheduled inspection or replacement. Inspections are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow station procedures that include inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination.

The program performs periodic sample inspections on closure bolting on pressure-retaining components within the scope of second license renewal that contain air or gas.

The program also includes preventive measures, such as, use of EPRI guidance for the installation, makeup, and material selections of bolted joints; prohibiting the use of lubricants containing molybdenum disulfide; and minimizing the use of high strength bolting to preclude or minimize loss of preload and cracking.

Aging management reviews have determined that high strength bolting material with actual yield strength of 150 ksi or greater is used for closure bolting on pressure-retaining components within the scope of second license renewal. There are no high strength bolts that are greater than 2 inches in diameter, or bolts with unknown yield strength within the scope of the Bolting Integrity program, therefore sample based volumetric inspection of closure bolting to detect indications of cracking is not applicable.

The program includes periodic sample inspections on submerged closure bolting on the ESW, HPSW, and fire protection pumps; submerged closure bolting on the Core Spray, HPCI, RHR, and RCIC system suction strainers; and submerged mechanical bolts on the 2AS008, 2BS008, 3AS008, and 3BS008 intake traveling screens. The program also performs periodic inspections on submerged closure bolting on the emergency cooling water pump.

The reduction of the number of minimum inspections to 19 from 25 bolts per unit for the ESW, HPSW and fire protection pumps, and mechanical bolting located on the 2AS008, 2BS008, 3AS008, and 3BS008 intake traveling screens is justified since the raw water environment in each intake bay is the same for Unit 2 and Unit 3. Also, the reduction of the number of minimum inspections to 19 from 25 bolts per unit on pressure-retaining components that contain air or gas in the carbon steel/ air-indoor uncontrolled and the stainless steel/ air-indoor uncontrolled material and environment combinations is justified since the air-indoor uncontrolled environment for Unit 2 and 3 is the same.

For sample based inspections in which acceptance criteria is not met the condition will be entered into the corrective action program. Conditions such as: loss of material; cracking; loss pf preload; degraded threads; active leakage; loose or missing bolts or nuts; and evidence of past leakage will be entered into the corrective action program where the condition will be evaluated. The degraded conditions will be evaluated relative to extent of condition against the total population of bolts under similar service conditions, to confirm the timing and extent of subsequent inspections to maintain the components' intended functions throughout the second period of extended operation. Site procedures will be enhanced so that as a minimum, additional inspection will be conducted where there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less. The additional inspections will be completed within the inspection interval for which the original sample based inspections are conducted. Inspection frequencies may be adjusted based on projected degradation rates.

The following bolting is not managed by in the Bolting Integrity aging management program.

- The bolting components for the reactor vessel closure head are managed by the Reactor Head Closure Stud Bolting (B.2.1.3) program.
- The Primary Containment (MC) pressure-retaining bolting is managed as part of the ASME Section XI, Subsection IWE (B.2.1.30) program.
- ASME Class 1, 2, 3, and MC piping and components support bolting, including NSSS component supports, is managed as part of the ASME Section XI, Subsection IWF (B.2.1.31) program.
- Structural bolting, other than ASME Class 1, 2, 3, and MC piping and component supports bolting is managed as part of the Structures Monitoring (B.2.1.34) program, and the Inspection of Water-Control Structures Associated With Nuclear Power Plants (B.2.1.35) program.
- Crane and hoist bolting is managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program.
- Heating and ventilation system bolted joints are managed by the External Surfaces Monitoring of Mechanical Components (B.2.1.24) program.
- Pressure-retaining bolting in a buried environment or underground with restricted access are inspected in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks (B.2.1.28) program.

NUREG-2191 Consistency

The Bolting Integrity aging management program will be consistent with the ten elements of aging management program XI.M18, "Bolting Integrity" specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191 recommends that the scope of the Bolting Integrity program manages aging of closure bolting on pressure-retaining components. The scope of the Bolting Integrity aging management program will also include the aging management of mechanical bolting on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens.
Program Element Affected: Scope of Program (Element 1)

Justification for Exception

Although the submerged mechanical bolts on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens are not closure bolting on pressure-retaining components, the Bolting Integrity aging management program has been determined to address the aging effects of loss of preload and loss of material as recommended in NUREG-2191.

The component, material, environment, and aging effects for these submerged mechanical bolts are the same as for submerged pressure-retaining closure bolts that are included within the scope of the NUREG-2191, XI.M18, Bolting Integrity program. The alternate means of inspection or testing provided within the NUREG-2191, XI.M18 program for submerged bolting, utilizing sample based visual inspections, has been determined to adequately manage the aging effects of loss of preload and loss of material for these submerged mechanical bolts.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Ensure that submerged carbon steel closure bolts on the ESW, HPSW, and fire protection pumps are inspected for loss of material and to confirm that the closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of closure bolting on these pumps during pump overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation. **Program Elements Affected: Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6).**

2. Ensure that submerged stainless steel mechanical bolts on the 2AS008, 2BS008, 3AS008, and 3BS008 Circulating Water Pump Structure intake traveling screens are inspected for loss of material and to confirm that the mechanical bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Inspection of mechanical bolting on these screens during overhaul and replacement activities may be credited during each 10-year period in the second period of extended operation. **Program Elements Affected: Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6).**

3. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for cracking and loss of material for the carbon steel/ air-indoor uncontrolled and the stainless steel/ air-indoor uncontrolled material and environment combinations. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 19 bolt inspections shall be performed each 10-year period during the second period of extended operation for each unit. Opportunistic inspections during maintenance activities may be credited during the same 10-year period. **Program Elements Affected: Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6).**

4. Ensure that closure bolts on pressure-retaining components that contain air or gas are inspected for loss of material for the carbon steel/ air-outdoor material and environment combination. In addition, the inspections will confirm that this closure bolting is leak tight applying inspection techniques, such as soap bubble testing, thermography, acoustic testing, or verifying closure bolting is hand tight. A minimum of 25 bolt inspections shall be performed each 10-year period during the second period of extended operation for both Units 2 and 3. Opportunistic inspections during maintenance activities may be credited during the same 10-year period. **Program Elements Affected: Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6).**

5. Revise site walkdown procedures to specify proper lighting and appropriate distances to adequately identify visible component leakage, evidence of past leakage, or other age-related degradation on pressure–retaining bolted joints that contain fluids such as water, oil, or steam. Cameras and video equipment may be used to supplement these inspections. **Program Element Affected: Detection of Aging Effects (Element 4).**

6. Revise existing repetitive tasks to provide guidance for the proper lighting and appropriate inspection distances to adequately identify loss of material for bolting in submerged environments. Cameras and video equipment may be used to supplement these inspections. **Program Element Affected: Detection of Aging Effects (Element 4).**

7. Ensure no fewer than five additional bolts are inspected for each sample based inspection that does not meet acceptance criteria, or 20 percent of the total bolt population of each applicable material, environment, and aging effect combination; whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis are performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval for which the original sample based inspections are conducted. **Program Element Affected: Corrective Actions (Element 7)**

Operating Experience

The following examples of operating experience provide objective evidence that the Bolting Integrity program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management activities associated with pressure-retaining closure bolting in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify that the existing aging management activities are being effectively implemented in the first period of extended operation. The information was collected from 2001 through 2016.

The aging management program effectiveness review included evaluation of plant-specific results against the applicable commitments identified in the first license renewal application, related RAI's, UFSAR Appendix Q, and NUREG-1769. The aging management program effectiveness review also included review of completed work orders and pertinent issues associated with closure bolting found in the corrective action program.

The review concluded that aging management activities associated with first license renewal commitments have been effectively implemented to maintain the intended functions for pressure-retaining closure bolting. For example, in response to confirmatory item 3.0.3.13.2-1, diver inspections of submerged closure bolting on the emergency cooling water pump are required on a 10-year frequency, as discussed in UFSAR Section Q.2.5, Outdoor, Buried and Submerged Component Inspection Activities. This commitment was tracked within the commitment tracking process and implemented by a station repetitive task. The inspection was most recently performed in May 2014 and no significant corrosion or abnormalities on emergency cooling water pump submerged closure bolting was identified.

In addition, a comprehensive review of the corrective action program was performed to identify issue reports related to closure bolting within the scope of the Bolting Integrity aging management program. The review identified approximately 100 issue reports that have been entered into the corrective action program reporting degraded closure bolting conditions, such as, degraded bolts, nuts, and threads; leaking closure joints; packing leaks, degraded gaskets; inadequate thread engagement, and missing bolts and nuts. This included degraded conditions on closure bolting on pressure-retaining components which contain fluids such as water, oil, or steam and systems which contain air or gas. The reported degraded conditions were evaluated and corrected in accordance with the corrective action program.

This operating experience provides objective evidence that first license renewal program commitments have been properly implemented and deficiencies identified with closure bolting on pressure-retaining components are entered into the corrective action program. The corrective action program is effective in evaluating and correcting degraded conditions. Continued implementation of the Bolting Integrity program will assure degraded conditions will be identified and corrected during the second period of extended operation.

2. In September 2002, discharge pressure on Unit 2 HPSW pump 2DP042 degraded significantly and the pump was physical observed to be "oscillating". Therefore, it was decided to replace the pump. When the degraded pump was removed from the intake it was observed that seven of the 12 pump column-to-discharge head bolts had sheared off.

The cause of this failure was attributed to poor worker practices and the use of an incorrect gasket. The stud failure was a result of the substitution of the 1/8 inch "Garlock" gasket sheet material for the Original Equipment Manufacturer (OEM) supplied 1/32 inch vegetable gasket that prevented the necessary compression to establish a rigid bolted joint.

Material analysis of the failed bolts conclusively determined that the cause of the failure was due to progressive stud fatigue failure and subsequent overload. The first stud to fail exhibited high-cycle and low-stress fatigue damage that occurred since the pump was rebuilt in 1989. As each stud failed, the adjacent studs picked up more load until they too failed. This eventually resulted in discharge flow to leak out of the flanged joint and the subsequent failure to pass surveillance testing.

Upon disassembly of the removed pump it was identified that sandwiched between the pump column and the discharge head flange was not an OEM supplied 1/32 inch vegetable gasket but a gasket fabricated from 1/8 inch "Garlock" gasket sheet material. The procedural required torque was sufficient for the OEM supplied 1/32 inch vegetable gasket, but was not enough for the 1/8 inch "Garlock" gasket sheet material to form a rigid flanged joint. This resulted in movement between the pump column and discharge head flange which led to the progressive stud failures. Extent of condition actions included the inspection of the other seven HPSW pumps on Units 2 and 3. These inspections found no additional failed bolts.

Corrective action included the review of the HPSW, ESW and ECW pump rebuilding procedures to ensure that specified torque values were adequate for each pump. This review used EPRI NP-5067, “Good Bolting Practices” as a reference source.

This example provides objective evidence that the corrective action program is effectively used to identify, evaluate, and correct degraded conditions, perform root cause evaluations, and implement extent of condition activities. The Bolting Integrity program applies established bolting torqueing requirements, and utilizes EPRI guidance.

3. In 1997 and 1998, the Unit 2 and 3 RHR and Core Spray System suction strainers were replaced. In 2007, during torus desludging and ISI program augmented inspection activities, diver inspections identified loose nuts on the 3B RHR suction strainer piping to torus penetration flange. This condition was entered into the corrective action program. This is a specially designed flanged connection intended to isolate the loads in the piping from those in the suction strainer. This flanged joint is secured using a double locked nut configuration which became loose since initial installation in 1998.

An extent of condition evaluation identified that the all eight Unit 3 RHR and Core Spray System suction strainers have the same configuration. The design of Unit 2 RHR and Core Spray System suction strainer to piping connections was found to be different, in that the Unit 2 flanges did not have the same double locked nut configuration. In addition, the same inspections on Unit 2 in 2004 did not identify similar loose nuts.

As a result of the extent of condition evaluation, similar bolted flanges on all eight Unit 3 RHR and Core Spray System suction strainers were checked and re-torqued, as required. Loose bolted connections were identified on the same bolted flanges on all but one of the eight RHR and Core Spray System suction strainers and more 40 bolts were re-torqued. An operability evaluation of the “as found” condition of all observed bolting deficiencies concluded that the strainers would have performed their intended functions during design basis events.

As a result of this event the ISI augmented inspection plan was updated to include the periodic inspection of bolting on these strainers and engineering developed improved contingency re-torqueing methods for bolted connections that are found loose.

Diver inspections of the eight strainers were performed in the next four Unit 3 refueling outages from 2009 to 2015. The trend in loose closure bolting, especially on the suction strainer piping to torus penetration flange, has significantly reduced. For example, during the 2015 inspection only two loose bolts were found on the A Core Spray System suction strainer. In addition, bolts that have been re-torqued with the improved methods have not become loose. Continued periodic inspection will be performed in accordance with the ISI augmented inspection plan.

The operating experience relative to the Bolting Integrity program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, long-term loss of material, loss of material, and loss of preload. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Bolting Integrity program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Bolting Integrity program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing Bolting Integrity program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.11 Open-Cycle Cooling Water System

Program Description

The Open-Cycle Cooling Water System aging management program is an existing preventive, mitigative, condition monitoring and performance monitoring program based on the implementation of NRC GL 89-13, and includes nonsafety-related portions of the open cycle cooling water system. The program includes: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, (c) periodic inspection and maintenance so that corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open cycle cooling water systems, (d) re-evaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. The program applies to components constructed of various materials including steel, cast iron, ductile iron, stainless steel, and copper alloys. There is no cement or cementitious piping within the scope of the program. This program includes guidance beyond the requirements contained in NRC GL 89-13, such as inputs from industry reports and documents (e.g., EPRI documents) that address operating experience such that aging effects are adequately managed.

The program manages piping, piping components, and heat exchanger components in safety-related and nonsafety-related raw water systems that are exposed to a raw water environment for loss of material, cracking, reduction of heat transfer, and flow blockage. The guidelines of NRC Generic Letter 89-13 are implemented through the site GL 89-13 activities for heat exchangers and the raw water corrosion program for piping and piping components. System and component testing, flushing, visual inspections, non-destructive examination, and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained.

The program includes those plant systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Test results and the results of visual inspections that do not meet acceptance criteria are evaluated in accordance with the corrective action program. For heat exchangers that are tested for heat transfer capability, test results are trended to verify adequacy of testing frequencies. For heat exchangers that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of inspection frequencies.

Safety-related piping is non-destructively examined to ensure that there is no loss of material which could result in loss of intended function. Examinations that do not meet acceptance criteria are evaluated in accordance with the corrective action program. For ongoing degradation due to specific aging mechanisms (e.g., MIC), the program includes trending of wall thickness measurements at susceptible locations to adjust the monitoring frequency and the number of inspection locations.

Inspections and tests are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow station procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The program does not manage loss of coating integrity for internal coatings or linings. Loss of coating integrity in raw water systems is managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program.

Aging effects associated with nonsafety-related service water systems not included within the scope of GL 89-13 (e.g., Service Water System) are managed by this program.

Aging effects associated with non-service water raw water systems (e.g., Domestic Water System, Travelling Water Screen System screen wash) are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program.

Fire water systems are managed by the Fire Water System (B.2.1.17) program.

The Open-Cycle Cooling Water System program does not manage loss of material or loss of preload in submerged bolting. These aging effects are managed by the Bolting Integrity (B.2.1.10) program.

NUREG-2191 Consistency

The Open-Cycle Cooling Water System aging management program will be consistent with the ten elements of aging management program XI.M20, "Open-Cycle Cooling Water System" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program element:

1. Provide procedural direction to perform additional inspections if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. These additional inspections will be conducted if any of the inspections does not meet acceptance criteria. No fewer than five additional inspections will be performed for each inspection that does not meet acceptance criteria, or 20 percent of each applicable

material, environment, and aging effect combination, whichever is less.
Program Element Affected: Corrective Actions (Element 7)

Operating Experience

The following examples of operating experience provide objective evidence that the Open-Cycle Cooling Water System program will be effective in assuring that intended functions are maintained consistent with the current licensing basis during the second period of extended operation:

1. In 2017, a program effectiveness review was performed in support of preparing the license renewal application for second license renewal. Aging management activities credited with managing the aging effects in the Emergency Service Water (ESW) System, High Pressure Service Water (HPSW) System, Emergency Cooling Water (ECW) System and in other systems' components using raw water as a cooling medium were assessed. The Open-Cycle Cooling Water System aging management program includes activities from several first license renewal aging management programs including the GL 89-13 Activities (UFSAR Section Q.2.8), Outdoor, Buried and Submerged Component Inspection Activities (Section Q.2.5), Inservice Inspection (ISI) Program (Section Q.1.8), Inservice Testing (IST) Program (Section Q.1.11), and High Pressure Service Water Radioactivity Monitoring Activities (Section Q.1.7) aging management programs. The purpose of the review was to verify the intent of the existing aging management programs, which is to identify and correct age-related degradation in raw water systems, is being effectively implemented during the first license renewal period of extended operation.

Operating experience within the corrective action program relative to raw water program activities from 2001 through 2016 was reviewed. The inspections and tests performed for raw water systems have identified age-related deficiencies associated with corrosion and fouling of internal surfaces of raw water components. These deficiencies have been identified during the performance of periodic aging management program activities by direct visual and volumetric inspections. Low flow and heat exchanger/cooler fouling has also been identified during periodic testing and inspection. The results of these inspections were evaluated under the corrective action program which provided the appropriate information to direct repair, replacement, or flushing of raw water system components. Inspection and testing results provide trendable and repeatable data on system and component conditions that inform margin management strategies and local flaw analysis tools, and provide input into mitigation efforts to reduce long-term operability threats as a result of raw water corrosion. These inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of these aging management programs.

Heat Sink Performance inspections documented in NRC Integrated Inspection Reports dated May 7, 2012, May 9, 2013, February 4, 2014, August 7, 2014, February 4, 2015, August 3, 2015, August 8, 2016 were also reviewed as part of the program effectiveness review. These inspections assessed existing aging management program activities including heat exchanger inspection and cleaning, heat transfer testing, biocide treatment, intake structure cleaning and inspection, and flushing. No findings were identified. A sampling of corrective action program reports for the ESW system, emergency diesel generator heat exchangers, and safety-related room coolers were also reviewed. The review verified that the PBAPS staff is appropriately identifying, characterizing, and correcting problems related to these systems and components, and that planned or completed corrective actions for the reported issues were appropriate.

In 2012 (Unit 2) and 2013 (Unit 3), pre-period of extended operation implementation of first license renewal aging management activities associated with the GL 89-13 Activities (UFSAR Section Q.2.8), Outdoor, Buried and Submerged Component Inspection Activities (Q.2.5), Inservice Inspection (ISI) Program (Q.1.8), Inservice Testing (IST) Program (Q.1.11), and High Pressure Service Water Radioactivity Monitoring Activities (Q.1.7) aging management programs was assessed by the site aging management program owners as part of a site-wide, license renewal implementation assessment. Results binders were assembled to support the NRC’s 71003, "Post-Approval Site Inspection for License Renewal" inspection. Results for heat exchanger/cooler cleaning and inspections, heat exchanger/cooler heat transfer tests, piping NDE, valve body and pump internal inspections, system flow tests, system pressure tests, intake structure inspection and cleaning, submerged component inspections, and HPSW radiation monitoring activities were included. In 2013 (Unit 2) and 2014 (Unit 3), pre-PEO implementation of these aging management programs was assessed via NRC regional inspection using inspection procedure 71003. Also included in the NRC’s 71003 review was the evaluation performed in 2012 that changed Peach Bottom’s piping inspection methodology for the GL 89-13 program. There were no adverse findings identified during these inspections.

With respect to raw water piping, Peach Bottom uses a risk based approach to aging management that centers around performing targeted UT inspections of selected piping locations that are representative or bounding to provide assurance that the piping systems remain operable and capable of performing their intended functions. To assess raw water piping aging management effectiveness, a review of maintenance work activities and associated inspection reports and corrective actions was performed.

A five-year time period coinciding with the start of the first period of extended operation was chosen for this review. From 2013 through 2017, 150 raw water inspections were performed, for an average of 30 per year. The inspections were distributed across the Emergency Service Water (ESW), High Pressure Service Water (HPSW), Emergency Cooling Water (ECW), and Service Water systems. UT data was accurately transferred to raw water program tracking and trending tools for evaluation. Leaks, and measurements below T-min that occurred during this time frame were entered into the corrective action program for resolution. These leaks and measurements below T-min were the result of localized corrosion. Piping repairs and replacements were performed to address these areas.

One implementation issue was identified during this review, and has been addressed by the station in the corrective action program. In 2016, and the first half of 2017, a number of raw water inspections were deferred. Inspections were selected in accordance with program guidelines, planned, and scheduled, but were deferred due to the need for further planning or other station work priorities. In total, 25 inspections were deferred in 2016 and 2017. To prevent future deferrals, this issue was entered into the corrective action program. In response, the station implemented several corrective actions. Six deferred inspections were emergently added to the scope of the 2017 fall Unit 3 refueling outage and completed. The remaining deferred inspections have been added to the 2018 inspection schedule. Corrective actions have been implemented to ensure readiness to perform future inspections as scheduled.

Peach Bottom raw water aging management is being effectively performed to ensure piping systems remain operable and will continue to perform their intended functions. Additionally, long-term aging management improvements are being evaluated. A long-term plan has been developed to ensure raw water piping material condition will support operation through the second period of extended operation. This includes selective piping replacements and plant modifications. Modifications being pursued include air cooling for the emergency diesel generators and ESW/HPSW crosstie, which will support retirement of the ESW system, HPSW system pressure reduction to increase the corrosion margin to end of life, and chemical treatment improvements to reduce vulnerabilities in raw water corrosion.

In summary, the aging management program effectiveness review determined that the programs are being implemented in accordance with the UFSAR Sections for GL 89-13 Activities (Section Q.2.8), Outdoor, Buried and Submerged Component Inspection Activities (Section Q.2.5), Inservice Inspection (ISI) Program (Section Q.1.8), Inservice Testing (IST) Program (Section Q.1.11), and High Pressure Service Water Radioactivity Monitoring Activities (Section Q.1.7).

This example provides objective evidence that existing aging management program activities are being effectively implemented to manage aging effects of in scope raw water system piping and components, and that deficiencies associated with the implementation of the program are identified and entered into the corrective action program for evaluation. Continued implementation of these activities will assure that piping and components within the scope of the programs will continue to perform their intended functions during the second period of extended operation.

2. A periodic five-year Focused Area Self-Assessment (FASA) for the Generic Letter 89-13 Program was conducted in March 2012. The purpose of the FASA was to determine if the GL 89-13 program is being properly executed to provide high equipment reliability, ensure reactor safety, and comply with regulatory requirements. The specific assessment objectives included:

- Program implementing activities
- Selected aspects of the NRC Heat Sink Inspection Plan 71111.07
- GL 89-13 Action I activities to limit flow blockage

- Program organization / human performance / interface issues
- Previous assessment open items

No program deficiencies or strengths were identified. The FASA resulted in the identification of 18 performance improvement recommendations which were in the area of documentation improvements, upgrading the computer program used to evaluate heat transfer data, better documentation of design parameters in test procedures, documentation of test instrument uncertainty, implementing industry OPEX, reviews of calculations for specific input parameters, and previous assessment action item completion. Passport assignments were created to track the resolution of the performance improvement recommendations. All improvement recommendations have been evaluated and actions taken as necessary.

This example provides objective evidence that the program manager for the Generic Letter 89-13 aging management program critically self-assesses program performance and self-identifies actions that support continuous improvement.

3. In September 2016, during the 24-month overhaul of the E4 emergency diesel generator (EDG), the as-found engineering inspection of the air cooler heat exchanger failed the visual inspection acceptance criteria for macrofouling. During the inspection, a total of five tubes were found completely fouled (two previously mechanically plugged and three plugged with macrofoulants). A maximum of two tubes are allowed to be completely plugged for tech spec operability. An engineering technical evaluation was performed to assess past operability. It was concluded that the as-found air cooler heat exchanger tube plugging did not adversely affect the air coolers safety function. The air cooler tubes were cleaned by removing the macrofoulants. The E4 EDG lube oil cooler and jacket water cooler were inspected and passed their respective acceptance criteria. There were no other concerns observed during the inspections of the E4 EDG heat exchangers. Because the E4 EDG air cooler heat exchanger failed its previous inspection for macrofouling, the inspection frequency was adjusted to every 12 months. Actions have been initiated to evaluate increasing the air cooler heat exchanger tube plugging margin through calculation or plant modification.

This example provides objective evidence that the existing aging management program activities are being effectively implemented to identify and manage aging effects of in scope heat exchangers serviced by raw water and that the results of inspection activities are used to inform and enhance the program. Deficiencies identified during inspection activities are entered into the corrective action program and appropriate corrective actions are taken to evaluate and correct the deficiencies.

4. In February 2014, Unit 2 High Pressure Service Water (HPSW) System piping was identified with less than minimum required wall thickness during NDE. The subject piping was located on the HPSW return pipe from the Unit 2 “A” RHR heat exchanger downstream of the discharge isolation valve. The NDE was being performed in accordance with PBAPS' Raw Water Piping Procedure extent of condition requirements. These extent of condition

inspections were the result of a HPSW pipe leak near the Unit 3 ”A” RHR heat exchanger discharge isolation valve.

The cause for emergent minimum wall thickness actions was determined to be due to incorrect monitoring intervals after past valve and pipe replacement work, as the configuration and turbulence at this location resulted in more unpredictable corrosion rates than other HPSW pipe areas. After the discharge isolation valve was changed in 2008 to a new valve model to reduce previous corrosion risks and increase pipe durability, pipe inspections to trend corrosion were reduced in frequency which eventually led to below acceptable thicknesses. This reduced inspection frequency was based on one data point three years after installing the new valve without additional data points for trending.

As an immediate corrective action, the flaws were removed and plugged branch connections installed. The affected piping was subsequently replaced in February of 2015. NDE was performed on the removed piping to aide in the evaluation of the susceptibility of other HPSW loops with similar age.

This example provides objective evidence that piping NDE inspections are effective in identifying degraded conditions caused by aging effects, and the corrective action program is effective in evaluating the conditions and implementing repair activities to correct the conditions prior to potential impacts to system intended functions.

5. A review of PBAPS operating experience over a 15-year period has revealed recurring internal corrosion (RIC) in raw water piping that is within the scope of the Open-Cycle Cooling Water System program. The program identifies inspection locations based on the risk associated with specific pipe locations. The risk is determined by the combination of piping corrosion susceptibility (based on material, piping size, piping configuration, flow velocity, and past inspection data) and the consequences of pipe leaks/ruptures or other integrity issues (e.g., piping below minimum required thickness). The selection of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure is an acceptable approach to address RIC as discussed in SLRA Section 3.3.2.2.7.

This example provides objective evidence that plant operating experience is reviewed for recurring internal corrosion, and appropriate actions are included in aging management programs.

The operating experience relative to the Open-Cycle Cooling Water System program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, flow blockage, loss of material, and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Open-Cycle Cooling Water System program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Open-Cycle Cooling Water System program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Open-Cycle Cooling Water System program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.12 Closed Treated Water Systems

Program Description

The Closed Treated Water Systems aging management program is an existing mitigative program that manages loss of material, cracking, and reduction of heat transfer in piping, piping components, tanks, and heat exchangers exposed to a closed cycle cooling water environment. The program will be enhanced to include condition monitoring activities. The Closed Treated Water Systems program includes: (a) nitrite-based water treatment, including pH control and the use of corrosion inhibitors to modify the chemical composition of the water such that the function of the components are maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation.

The license renewal systems with components managed by the Closed Treated Water Systems aging management program include; Chilled Water System, Emergency Diesel Generator System, Post Accident Sampling System, Primary Containment Isolation System, Process Sampling System, Reactor Building Closed Cooling Water System, Reactor Recirculation System, and Turbine Building Closed Cooling Water System.

The Closed Treated Water Systems program activities are implemented through station procedures. Mitigative activities include utilizing nitrite-based chemistry controls to minimize the age-related degradation of components exposed to a closed treated water environment. The performance of sample analyses assures water chemistry parameters are maintained within the goal ranges specified by procedures based on EPRI closed cooling water chemistry guidelines. The PBAPS Closed Treated Water Systems aging management program specifies the use of EPRI 3002000590, “Closed Cooling Water Chemistry Guideline,” Revision 2, 2013. Monitoring of water chemistry parameters also assures contaminants are kept below applicable limits to prevent or limit corrosion. Corrosion coupon testing is not used; corrosion monitoring is performed by monitoring for total iron and total copper which indicates if active corrosion is occurring. Testing and treating for microbiological growth is performed. Condition monitoring activities will include opportunistic visual inspections and periodic inspections using techniques capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects as described below.

Periodic inspections for indication of loss of material, cracking, and fouling of a representative sample will be performed, at a minimum, in each 10-year period during the second period of extended operation. The inspections will include opportunistic visual inspections and periodic inspections to satisfy the sample size requirements using techniques capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects. Opportunistic visual inspections will be performed whenever a system boundary is opened.

The inspections will focus on the components most susceptible to aging because of time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water. A representative sample is 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 19 components per population at each unit. At least 20 percent of the surface area will be 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 number of inspections. The reduced total number of inspections for a multi-unit site is applicable due to the environmental conditions, operating history, and system design parameters (heat load, flow, and temperature) between the units are similar enough such that the aging effects are not occurring differently. Therefore, the maximum number of inspections will be 19 per population at each unit. Changes to water chemistry practices and to plant equipment and operating conditions (including power rerates) have been performed on both units at approximately the same time. Water chemistry programs monitor various chemistry parameters, and require out-of-specification conditions to be corrected under the corrective action program.

Heat transfer capability of heat exchanger surfaces will be evaluated by either visual inspections to determine surface cleanliness, or functional testing to verify that design heat removal rates are maintained.

Due to the water chemistry controls, no age-related degradation is expected; therefore, any detectable loss of material, cracking, or fouling will be evaluated in the corrective action program. Identified age-related degradation will be projected until the next scheduled inspection and results are evaluated to confirm that the sampling bases will maintain the component’s intended functions throughout the second period of extended operation. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, and loss of material.

Additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections will be determined in accordance with the corrective action program; however, no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections include inspections at both Unit 2 and 3 with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval in which the original inspection was conducted.

Inspections will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME

Code. Non-ASME Code inspections will follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The program will be enhanced, as noted below, to provide reasonable assurance that the Closed Treated Water Systems program will manage the aging effects of loss of material, cracking, and reduction of heat transfer during the period of extended operation.

NUREG-2191 Consistency

The Closed Treated Water Systems aging management program will be consistent with the ten elements of aging management program XI.M21A, "Closed Treated Water Systems" specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. NUREG-2191 specifies the use of EPRI 1007820, “Closed Cooling Water Chemistry Guideline,” Revision 1, 2004, for monitoring and controlling closed cooling water chemistry, however, the PBAPS Closed Treated Water Systems aging management program specifies the use of EPRI 3002000590, “Closed Cooling Water Chemistry Guideline,” Revision 2, 2013, for monitoring and controlling closed cooling water chemistry. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

Justification of Exception

EPRI reports such as “Closed Cooling Water Chemistry Guideline” are industry reports, which are periodically reviewed and revised by industry experts to incorporate recent industry operating experience and technology improvements. EPRI “Closed Cooling Water Chemistry Guideline” was revised, in 2013, to include advances in water-treatment chemicals, improved monitoring technologies, and new industry operating experience. PBAPS closed cooling water chemical treatment program is a nitrite-based program. The specific water chemistry parameters monitored, acceptable range, and sampling frequency specified in EPRI 3002000590, “Closed Cooling Water Chemistry Guideline,” Revision 2, 2013 remained unchanged from EPRI 1007820, “Closed Cooling Water Chemistry Guideline,” Revision 1, 2004; therefore, use of EPRI 3002000590 is acceptable.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program elements:

1. Perform condition monitoring including opportunistic visual inspections and sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the second period of extended operation. The rate of identified degradation will be projected until the next

scheduled inspection. Additional sample-based inspections will be performed if aging effects are identified. If those inspections identify aging effects, the corrective action program will be used to determine the extent of condition and extent of cause to determine the further extent of inspections. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)**

Operating Experience

The following examples of operating experience provide objective evidence that the Closed Treated Water Systems program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed in support of preparing the license renewal application for second license renewal. The purpose of the effectiveness review was to verify the existing Closed Cooling Water Chemistry Activities aging management program as described in UFSAR Section Q.1.3 is being effectively implemented in the first license renewal period of extended operation. This program manages loss of material, cracking, and reduction of heat transfer in components exposed to closed cooling water through measures that monitor and control closed cooling water chemistry. The aging management program effectiveness review was comprised of a review of chemistry results, chemistry trends, and issues in the corrective action program associated with various closed cooling water systems such as, turbine building closed cooling water, reactor building closed cooling water, drywell chilled water, control room chilled water, and emergency diesel generator jacket water from 2002 to 2017. Although some instances of system leakage did occur in closed cooling water systems, it was identified prior to loss of system function and corrected through the corrective action program. Closed cooling water chemistry was either maintained within industry guidelines, or if chemistry parameters exceeded an industry action level, the issue was entered into the corrective action program and actions were taken to restore the parameter to within industry guidelines. The activities to monitor and control closed cooling water chemistry has resulted in the effective implementation of this aging management program.

This example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the Closed Cooling Water Chemistry Activities aging management program (known as the Closed Treated Water Systems aging management program during the second period of extended operation) will effectively manage aging prior to failure or loss of intended function during the second period of extended operation.

2. In February 2010, a Unit 2 reactor building closed cooling water chemistry sample analysis identified a system leak based on the inability to maintain proper system chemistry without increased chemical additions. This condition was entered into the corrective action program. It was also noted that operations had identified an increase in the frequency of filling the system head

tank. A walkdown of the system and an investigation into the location of the leak was performed. The Unit 2 “B” reactor building closed cooling water heat exchanger was identified as leaking. The heat exchanger was isolated and repaired, and chemistry parameters returned to normal without the need for frequent chemical additions.

This example provides objective evidence that: a) adverse trends found during chemistry monitoring activities are documented in the corrective action program, b) investigations are performed to identify the cause of the adverse trend, and c) actions are taken to correct plant equipment problems and restore chemistry parameters to acceptable levels.

3. In June 2016, during the regular monthly sampling of the E2 emergency diesel jacket cooling water, the chemistry technician noted that the sample had a peculiar smell and a milky white appearance. The normal chemistry analyses were performed on the sample. Conductivity, pH, tolytriazole concentration, nitrite and other high-level anion concentrations were within goal limits for a nitrite-inhibited system. However, ATP (adenosine triphosphate) and ammonia indicated the presence of microbiological activity. A feed and bleed was performed on the system to restore all chemistry parameters to within the specified range. An investigation determined that maintenance was recently performed on the E2 emergency diesel generator and contaminants were introduced into the system while the jacket water system was open. A work process change was made which added an activity for chemistry to evaluate the maintenance work and provided recommendations on flushing the emergency diesel generator closed cooling water systems prior to filling the system.

This example provides objective evidence that: a) abnormal results found during chemistry monitoring activities are documented in the corrective action program, b) investigations are performed to identify the cause of the abnormal results, and c) actions are taken to correct the cause.

4. In November 2015, a sample of the Unit 3 drywell chilled water system, a normally clean (non-radioactive) system showed high levels of Sodium-24 and Cobalt-60. Sampling for radioactivity is recommended by industry guidelines for closed cooling water systems. The high levels of Sodium-24 and Cobalt-60 were entered into the corrective action program. The contamination occurred during system start-up activities and was determined to be a result of leakage through the valves which allow the Unit 3 drywell chilled water system to be cross-connected to the Unit 3 reactor building closed cooling water system, a known potentially contaminated system. A feed and bleed of the Unit 3 drywell chilled water system was performed to reduce contamination levels.

This example provides objective evidence that: a) abnormal results found during chemistry monitoring activities are documented in the corrective action program, b) investigations are performed to identify the cause of the abnormal results, and c) actions are taken to restore chemistry parameters to within acceptable limits.

The operating experience relative to the Closed Treated Water Systems program did not identify an adverse trend in performance. The current preventive program has been effective in maintaining closed treated water chemistry parameters in accordance with accepted industry guidelines. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Closed Treated Water Systems program, with enhancements to perform opportunistic and periodic inspections, will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Closed Treated Water Systems program will provide reasonable assurance that the cracking, loss of material, and reduction of heat transfer aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing condition monitoring program that manages the aging effects of loss of material due to corrosion and wear, cracking, deformation, and indications of loss of preload for load handling bridges, structural members, structural components and bolted connections for cranes, hoists, and monorail beams in air-indoor uncontrolled, air-outdoor, and treated water environments. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.” The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging effects.

The scope of cranes, hoists, monorails, and refueling equipment within the scope of license renewal is based on those that must comply with NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.” Overhead lifting equipment that operates over safety-related equipment is included within the scope of license renewal. Approximately 40 cranes and hoists, including the reactor building cranes, turbine building cranes, numerous equipment handling cranes, hoists, and monorails are managed by the program. Also within the scope of the program are handling systems that handle ‘light’ loads including equipment, tools, and fuel, over fuel and safety-related equipment within the spent fuel pool and reactor cavity.

Inspection frequency and scope is in accordance with the recommendations for periodic inspection within the ASME B30 series of standards. Periodic inspections are performed annually for frequently operated handling systems. For handling systems that are infrequently in service, such as those only used during refueling outages or for specific maintenance activity, periodic inspections are performed just prior to use. Aging effects that are identified by inspections are entered into the corrective action program for evaluation and repair.

NUREG-2191 Consistency

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be consistent with the ten elements of aging management program XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Provide additional guidance to include inspection of crane-related bridges, structural members, and structural components for deformation, cracking, and loss of material due to corrosion or wear; and associated bolted connections for loss of material, cracking, and indications of loss of preload. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), and Detection of Aging Effects (Element 4)**

2. Provide procedural direction to document deficiencies identified during inspection activities within the corrective action program. **Program Elements Affected: Monitoring and Trending (Element 5), Corrective Actions (Element 7), and Confirmation Process (Element 8)**

3. Provide site-specific procedural direction to evaluate and repair visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload in accordance with ASME B30.2 or other applicable industry standard in the ASME B30 series. **Program Elements Affected: Acceptance Criteria (Element 6) and Corrective Action (Element 7)**

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the cranes, hoists, and refueling handling systems covered by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems in support of preparing the license renewal application for second license renewal. The license renewal commitment described in UFSAR Section Q.1.14, Crane Inspection Activities, requires periodic visual inspections of in scope handling systems, performed in accordance with the guidance provided within the ASME B30 series of standards. The purpose of the review was to verify the intent of the existing Crane Inspection Activities aging management program, which is to identify and correct age-related degradation of in scope handling systems, is being effectively implemented during the first license renewal period of extended operation.

The aging management program effectiveness review included a review of maintenance history for documented completion of periodic inspections from 2010 through 2016, and a review of operating experience within the corrective action program for identified age-related degradation of in scope handling systems from 2001 through 2016. The review identified that three handling systems needed to be added to the scope of the Crane Inspection Activities program because new or revised analysis identified that safety-related SSCs beneath or nearby to the handling system could be affected by handling system failure. This issue was entered into the corrective action program. These handling systems were considered newly identified SSCs under 10 CFR 54.37(b) and reported to the NRC. Review of the work order history for these three handling systems confirmed that the periodic inspections required by the Crane Inspection Activities program were consistently performed annually during the period of extended operation.

The aging management program effectiveness review included a review of maintenance history for documented completion of periodic inspections from 2010 through 2016, and a review of operating experience within the corrective action program for identified age-related degradation of in scope handling systems from 2001 through 2016. The inspections performed per the Crane Inspection Activities program have identified very few age-related deficiencies associated with passive structural and bolting components; and those identified have been minor in significance with evaluations that concluded that the structural integrity of the crane/hoist structure was not affected. This is as expected since almost all the handling systems within the scope of the program are infrequently used and are in an air-indoor environment. These periodic inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of this aging management program. In 2013, pre-PEO implementation of the Crane Inspection Activities program was also assessed via NRC regional inspection using inspection procedure 71003, with no adverse findings identified.

The aging management program effectiveness review determined that the program is being implemented in accordance with the Crane Inspection Activities program as described in UFSAR Section Q.1.14.

This operating experience example provides objective evidence that periodic visual inspections and the corrective action program are effectively managing the aging effects of the handling systems within the scope of license renewal and that continued implementation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will assure that these handling systems will continue to perform their intended functions during the second period of extended operation.

2. In July 2009, during periodic inspection of the outdoor Circulating Water Pump Structure crane, the concrete around a tornado tie-down connection was found damaged, likely due to periodic freezing of moisture within the pits housing the connections, and the issue was entered into the corrective action program. Engineering evaluation determined that the damage was minor and recommended a repair method. In May 2011, periodic inspection also identified that a turnbuckle on a tornado tie-down connection was damaged. This issue was entered into the corrective action program and engineering evaluation determined that the damaged turnbuckle needed to be replaced. In August 2011, the damaged turnbuckle was replaced and the damaged concrete was repaired.

In May 2012, during periodic inspection of the Circulating Water Pump Structure crane, the tornado tie-down connections were found to be corroded and the issue was entered into the corrective action program. Engineering evaluation determined that the damage did not render the tie-down connections inoperable and recommended applying a coating to them. In June 2013, the tie-down connections were coated.

These examples provide objective evidence that periodic inspections are effective in identifying minor degraded conditions caused by aging effects, and the corrective action program is effective in evaluating the conditions and implementing repair activities to correct the conditions prior to the condition potentially impacting the intended function.

3. In February 2014, during periodic inspection of the “A” turbine building crane, several loose hold-down bolts and broken lock washers were identified on the bridge runway rails. Also, a misalignment in the rails was causing a bump in the rail. The issue was entered into the corrective action program. Engineering evaluation determined that the condition did not impact structural integrity of the crane. In March 2015, the loose and damaged hardware was repaired or replaced and the rails were re-aligned to correct the condition.

This example provides objective evidence that periodic inspections are effective in identifying minor degraded conditions caused by aging effects, and the corrective action program is effective in evaluating the conditions and implementing repair activities to correct the conditions prior to the condition potentially impacting the intended function.

The operating experience relative to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, and loss of preload. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.14 Compressed Air Monitoring

Program Description

The Compressed Air Monitoring aging management program is an existing condition monitoring program that consists of monitoring moisture content and corrosion, and performance of the compressed air system, including: (a) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits, and (b) inspection of components for indications of loss of material due to corrosion. The program manages loss of material in carbon steel, stainless steel, copper alloy, and aluminum alloy piping, piping components, valve bodies, accumulators, hoses, and strainer elements in an air-dry environment.

This program is based on the PBAPS response to NRC GL 88-14 and INPO's SOER 88-01. It also relies on the guidance from the ASME operations and maintenance standards and guides (ASME OM-S/G-2012, Division 2, Part 28), ANSI/ISA-7.0.1-1996, and EPRI TR–10847 for testing and monitoring air quality and moisture. Additionally, opportunistic visual inspections of component internal surfaces are performed for signs of loss of material due to corrosion.

Program activities include air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits, and inspections of the internal surfaces of compressed air system components for signs of loss of material due to corrosion. Air quality test data is analyzed against established acceptance criteria. Trending is performed to ensure aging effects on passive components are identified. The effects of corrosion and presence of contaminants are detected during periodic tests, and preventive maintenance inspections of compressed air system components. Inspections of accessible internal surfaces of components provide assurance that the systems within the scope of license renewal will perform their intended function.

Results from inspections are compared with established acceptance criteria to provide for timely detection of aging effects. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant age-related degradation. Deficiencies are documented in the corrective action program and evaluations are performed for test or inspection results that do not satisfy established criteria. The corrective action program ensures that the conditions adverse to quality are promptly corrected. The site corrective action program is implemented in accordance with the requirements of the 10 CFR Part 50, Appendix B quality assurance program.

NUREG-2191 Consistency

The Compressed Air Monitoring aging management program will be consistent with the ten elements of aging management program XI.M24, "Compressed Air Monitoring" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform daily inspection of instrument nitrogen after dryer desiccant for signs of moisture. Results will be recorded and reviewed to determine if corrective actions are required. **Program Elements Affected: Detection of Aging Effects (Element 4) and Monitoring and Trending (Element 5)**

2. Perform opportunistic visual inspections of component internal surfaces exposed to a dry air environment for signs of loss of material due to corrosion. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Compressed Air Monitoring program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an effectiveness review of the GL 88-14 implementation was performed in support of preparing the license renewal application for second license renewal. This consisted of review of completed air quality tests for the instrument air and instrument nitrogen systems, and issue reports input into the station corrective action program. Information was collected for the time period from 2001 through 2016. Sixty-one completed air quality tests were reviewed.

A total of 49 issues within the corrective action program were identified during the same period. These issues primarily consisted of unsatisfactory test results, material condition issues, results of maintenance on system components, and alarm conditions requiring evaluation.

The review identified the following:

- System air quality testing is performed as specified by the implementing procedures. The tests include acceptance criteria as described by the program. Test data was properly recorded and reviewed. No instances of failure to perform testing at the required frequency were identified.

- Of the 61 tests reviewed, 11 resulted in unsatisfactory results. These unsatisfactory tests results were documented, and were entered into the corrective action program. Corrective actions consisted of system maintenance, retesting, and in some cases, system or component modifications to prevent future occurrences.

- Of the 11 unsatisfactory test results, eight were during performance of Unit

2 instrument nitrogen system testing. All test failures were the result of moisture content exceeding the acceptance criteria. Performance of this test required corrective actions and retesting the last four consecutive times it was performed (2010, 2012, 2014, and 2016). This condition was entered into the corrective action program to investigate and correct this trend.

- Issue reports are being generated for maintenance activities that identify abnormal conditions, and corrective actions are implemented.

This review provides objective evidence that the monitoring and testing of air quality and moisture, required by GL 88-14, and resulting corrective actions are effective in managing loss of material for compressed air system piping and components to ensure reliable long-term operation of in scope compressed air systems. This objective evidence, combined with the establishment of the enhanced Compressed Air Monitoring aging management program, provides reasonable assurance that loss of material will be effectively managed and the compressed air systems will continue to perform their intended functions during the second period of extended operation.

2. Instrument nitrogen quality tests are performed once per operating cycle in accordance with GL 88-14 requirements. In 2014, an instrument nitrogen air quality test was performed on Unit 2. Samples were taken and analyzed for moisture content, dew point, hydrocarbons, and particulates. Moisture content was measured as 1275 ppm for the “A” header, and 1300 for the “B” header, above the limit of 750 ppm. This issue was entered into the corrective action program. Engineering recommended blow down of the instrument nitrogen receivers and replacement of desiccant in the after dryer. After completion of the recommended actions, the test was re-performed satisfactorily.

This example provides objective evidence that the Compressed Air Monitoring program is effectively monitoring air quality, and that the corrective action program is effectively used to document degraded conditions, and to evaluate conditions for action prior to loss of intended function.

3. In 2007, as the result of repeat issues of unreliable dew point measurements, an issue was entered into the corrective action program to replace the instrument air dryer moisture meters. The meters are used for measuring dew point during instrument air quality testing. A design change was initiated, and in 2008, meter replacement was completed. This corrective action resulted in improved dew point measurement reliability.

This example provides objective evidence that dew point data is reviewed against acceptance criteria, and the corrective action program is effectively used to address issues that impact the ability to monitor system performance.

4. In 2009, during preventative maintenance for the Unit 2 “A” instrument nitrogen compressor, both cylinders were found to have rust and corrosion due to moisture. Water was found in one of the cylinders and exhaust manifold. Maintenance determined that the moisture was coming from the defective diaphragm in the compressor cooling water outlet valve. When the valve was removed from the header and inspected, it was found that the diaphragm had

lost it resiliency and was cracked in several places. The valve was replaced with a new valve during the compressor maintenance. As an extent of condition corrective action, the Unit 2 “B” instrument nitrogen system cooling water outlet valve was proactively replaced. This eliminated the potential for similar moisture issues within the “B” instrument nitrogen header. In addition, to reduce the risk of a similar failure and a future moisture intrusion event, the annual air compressor preventive maintenance work order was revised to inspect the cooling water outlet valve and replace as required.

This example provides objective evidence that system maintenance is effective in identifying internal component degradation, and the corrective action program is effectively used to adjust inspections and maintenance as required to ensure there is no loss of system function.

The operating experience relative to the Compressed Air Monitoring program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Compressed Air Monitoring program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Compressed Air Monitoring program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Compressed Air Monitoring program will provide reasonable assurance that the loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.15 BWR Reactor Water Cleanup System

Program Description

The BWR Reactor Water Cleanup System program is an existing condition monitoring and mitigation program that includes the requirements to perform augmented inservice inspection (ISI) to manage stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) for stainless steel Reactor Water Cleanup (RWCU) System piping welds outboard of the second (outboard) primary containment isolation valves. Piping that contains reactor coolant or treated water at a temperature above 200 degrees Fahrenheit during power operation, and has a nominal diameter of 4 inches or larger, regardless of ASME Code classification is included within the scope of the program. The program includes the measures delineated in NUREG-0313, Revision 2, NRC Generic Letter (GL) 88-01 and its Supplement 1, and any applicable NRC-approved alternatives to these guidelines and ISI in conformance with ASME Code, Section XI. The program is implemented in conjunction with the Water Chemistry (B.2.1.2) program to minimize the potential of cracking due to SCC or IGSCC in a treated water environment.

The BWR Reactor Water Cleanup System program includes acceptable inspection alternatives to staff positions delineated in NRC GL 88-01 as described in NRC GL 88-01, Supplement 1. For PBAPS Units 2 and 3, the NRC previously approved a reduced extent and schedule for inspection of IGSCC susceptible welds within the RWCU system that are outboard of the second isolation valves. The approved alternate extent and schedule is to perform ISI on two percent of the IGSCC susceptible welds during each refueling outage.

Flaws that exceed the acceptance criteria of ASME Code, Section XI, Subsection IWB-3500 are entered into the corrective action program to be repaired, replaced, or evaluated as acceptable for return to service in accordance with Subsection IWB-3600. NRC approval of repair or evaluation dispositions is required prior to return to service, consistent with NRC GL 88-01 guidelines.

NUREG-2191 Consistency

The BWR Reactor Water Cleanup System aging management program is consistent with the ten elements of aging management program XI.M25, "BWR Reactor Water Cleanup System" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Reactor Water Cleanup System program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the augmented ISI program in place to implement the commitment to perform ISI on IGSCC susceptible welds in the RWCU system that are outboard of the second isolation valve in support of preparing the license renewal application for second license renewal. Augmented ISI on these welds is required in accordance with licensing commitments in response to NRC GL 88-01 and its Supplement 1. This augmented ISI program is part of the first license renewal Inservice Inspection (ISI) Program described in UFSAR Section Q.1.8. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage cracking by performing ISI on IGSCC susceptible welds, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of inspection records during the fourth 10-year ISI Inspection Interval (November 2008 through December 2018) and pertinent issues found in the corrective action program from 2001 to 2016, searching for age-related degradation of piping and welds within the scope of the BWR Reactor Water Cleanup System program.

The review identified that volumetric examinations of piping welds within the scope of the BWR Reactor Water Cleanup System program are being performed in accordance with PBAPS commitments in response to NRC GL 88-01 as further described in Operating Experience examples 2, 3 and 4 below. The review identified that examinations performed within the program are effective at identifying age-related degradation of in scope components. Age-related issues were evaluated and corrected in accordance with ASME Code, Section XI and requirements delineated in NRC GL 88-01, resulting in effective implementation of this aging management program. The review also concluded that the piping welds within the scope of the BWR Reactor Water Cleanup System program are in excellent condition on Units 2 and 3.

This operating experience provides objective evidence that the current Inservice Inspection (ISI) Program is being effectively implemented to manage cracking in accordance with the PBAPS commitments in response to NRC GL 88-01. Continued implementation of the BWR Reactor Water Cleanup System program will assure that the piping welds within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. On Unit 2, during the fourth 10-year ISI Inspection Interval (November 2008 through December 2018), volumetric examinations are being performed during each refueling outage on two percent of the welds within the population of IGSCC susceptible welds (three welds) that are outboard of the second RWCU system isolation valve. No indications of cracking were identified.

This example demonstrates that volumetric examinations are being performed on IGSCC susceptible welds within the scope of the program in accordance with the extent and schedule previously approved by the NRC.

3. On Unit 3, during the fourth 10-year ISI Inspection Interval (November 2008 through December 2018), volumetric examinations are being performed during each refueling outage on two percent of the welds within the population of IGSCC susceptible welds (two welds) that are outboard of the second RWCU system isolation valve. In October 2017, a crack-like flaw indication was identified by volumetric examination in the heat affected zone of an IGSCC susceptible weld (weld 12-13-12) between piping and an elbow in the RWCU system return piping outboard of the second isolation valve. The condition was entered into the corrective action program and the NRC was informed of the condition. The elbow and associated welds were replaced, removing the flawed weld from service. As a result of the condition, two additional welds within the scope of the BWR Reactor Water Cleanup System program were examined with no additional indications identified. No other indications of cracking were identified during the fourth 10-year ISI interval.

This example demonstrates that volumetric examinations are being performed on IGSCC susceptible welds within the scope of the program in accordance with the extent and schedule previously approved by the NRC. This example also demonstrates that volumetric examinations are capable of detecting cracking in welds, and that when cracking indications are identified the condition is addressed within the corrective action program in accordance with the PBAPS licensing commitments to implement NRC GL 88-01 guidelines and staff positions.

4. On Unit 2, in 1996 a volumetric examination identified a crack-like indication in the heat affected zone of an IGSCC susceptible weld (weld 12-14-5) in the RWCU system return piping outboard of the second isolation valve. The condition was entered into the corrective action program to address the condition and the indication was mitigated by weld overlay performed in accordance with NRC-approved Code Case N-504. The condition and the repair disposition were reported to the NRC in accordance with NRC GL 88-01 guidelines. As a result of the condition, two additional welds located in the same horizontal run of piping were examined with no additional indications identified. As a result of the cracking indication, weld 12-14-5 was classified as IGSCC Category E as defined within NRC GL 88-01, and is being periodically re-examined in accordance with the extent and schedule defined in NRC-approved BWRVIP-75-A for IGSCC Category E welds. Weld 12-14-5 was most recently examined in 2012, with no recordable indication identified within the weld overlay. Weld 12-14-5 is the only Category E weld on Units 2 and 3 within the populations of IGSCC susceptible welds that are outboard of the second RWCU system isolation valves.

This example demonstrates that volumetric examinations are capable of detecting cracking in welds, and that when cracking indications are identified the condition is addressed within the corrective action program in accordance with the PBAPS licensing commitments to implement NRC GL 88-01 guidelines and staff positions.

The operating experience relative to the BWR Reactor Water Cleanup System program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Reactor Water Cleanup System program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Reactor Water Cleanup System program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing BWR Reactor Water Cleanup System program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.16 Fire Protection

Program Description

The Fire Protection aging management program is an existing condition and performance monitoring program that manages the identified aging effects for the fire barriers and the low pressure carbon dioxide systems and associated components in air-indoor uncontrolled and air-outdoor environments through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. System functional tests and inspections are performed in accordance with guidance from National Fire Protection Association Codes and Standards. The program applies to piping, piping components, spill retaining curbs, and fire barriers (doors and dampers, penetration seals, walls, and slabs). Fire Protection component materials consist of carbon steel, galvanized steel, concrete, concrete block, grout, subliming and cementitious fireproofing, elastomers, and aluminum silicate.

The Fire Protection program monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation. The program utilizes visual inspections of fire barrier penetration seals for signs of degradation such as loss of material, cracking/shrinking, wear, seal separation from walls and components, separation of layers of material, and changes in material properties through periodic inspection. The program specifies visual examinations of the fire barrier walls, ceilings, and floors in structures within the scope of license renewal for signs of degradation such as loss of material and cracking/spalling. Periodic visual inspections and functional tests are used to manage the aging effects of fire doors and fire damper assemblies. Inspection and testing frequencies are consistent with the Technical Requirements Manual. These inspections and tests are implemented through station procedures and recurring task work orders. Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the corrective action program for proper disposition.

The program will also provide for aging management of external surfaces of the low pressure carbon dioxide fire suppression system components that are within the scope of license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the low pressure carbon dioxide fire suppression system components in accordance with the Technical Requirements Manual.

NUREG-2191 Consistency

The Fire Protection aging management program will be consistent with the ten elements of aging management program XI.M26, "Fire Protection" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform periodic visual inspection every 18 months for identification of corrosion that may lead to loss of material on the external surfaces of the low pressure carbon dioxide fire suppression systems. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)**

2. Perform periodic visual inspection of combustible liquid spill retaining curbs every 24 months. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Protection program will be effective in assuring that intended functions are maintained consistent with the current licensing basis during the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed for the Fire Protection Activities program, as described in UFSAR Section Q.2.9, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to identify and address aging effects for fire barrier penetration seals; fire barrier walls, ceilings, and floors, fire doors, fire damper assemblies, structural steel fireproofing, and fire wraps is being effectively implemented in the first period of extended operation.

Information was collected for the period time from 2003 to 2016. The program effectiveness review was comprised of a review of surveillance tests, and issues found in the corrective action program associated with inspections of fire barrier components such as fire barrier walls, ceilings, and floors, penetration seals, fire doors, fire damper assemblies, structural steel fireproofing, and fire wraps. In addition, internal Fire Protection program audit reports by Exelon Nuclear Oversight and external Fire Protection program inspections by the NRC were also reviewed to determine the program effectiveness. The review identified that age-related degradation of in scope SSCs is identified and managed through the performance of surveillance test inspections, functional tests, and the corrective action program. Age-related issues identified during the inspections were evaluated by engineering and corrected within the corrective action program resulting in effective implementation of this aging management program.

Therefore, the aging management program effectiveness review determined that the program is being implemented in accordance with the Fire Protection Activities program described in UFSAR Section Q.2.9.

This operating experience provides objective evidence that the surveillance inspections, maintenance practices, and corrective action program effectively monitor fire barrier penetration seals; fire barrier walls, ceilings, and floors, fire doors, fire damper assemblies, structural steel fireproofing, and fire wraps to assure that these components will continue to perform their intended functions during the first period of extended operation. In addition, this operating experience provides objective evidence that this aging management program has effectively managed age-related degradation such as concrete cracking and spalling, corrosion, loss of material, loss of bond (e.g. seal separation, separation of layers and shrinkage), hardening and loss of strength, and physical damage (e.g., rupture or puncture of seals) prior to loss of intended function. Continued aging management of these components in accordance with the Fire Protection program assures that intended functions will be maintained during the second period of extended operation.

2. In June 2007, during fire door surveillance inspections a damaged fire door was identified. A worn and frayed fire door air seal was identified on the upper door jamb. The door condition was degraded, but the door remained capable of performing its design function to close and latch. Upon discovery, the condition was entered into the corrective action program and evaluated by engineering for operability. After evaluation, the door was declared operable since the frayed air seal did not adversely impact the fire protection function of the fire door. The seal was subsequently repaired.

This example provides objective evidence that the visual inspections performed in accordance with the Fire Protection program are adequate to identify deficient conditions and correct them prior to loss of intended function.

3. In March 2009, during fire barrier penetration seal surveillance inspections, a seal failed the inspection criteria defined by the procedure and associated detail drawing. The penetration seal was found with a void in the foam material 4 to 6 inches deep. The condition was entered into the corrective action program and evaluated by engineering for operability. The evaluation determined that adequate fire barrier materials existed to assure the fire barrier function. The seal was reworked to conform to detail requirements.

This example demonstrates that the Fire Protection program is effective to identify degraded conditions and correct them prior to loss of intended function.

4. In July 2016, during fire barrier surveillance inspections a crack in a block wall was found around one masonry block. The mortar around the block had become detached. The crack in the wall did not meet the inspection criteria defined by the procedure. The condition was entered into the corrective action program and evaluated by engineering. The fire system manager determined that the block wall would still perform its design function as a fire barrier. A work request was initiated and implemented to rework the wall and prevent further degradation.

This example demonstrates that the Fire Protection program is effective to identify degraded conditions and correct them prior to loss of intended function.

The operating experience relative to the Fire Protection program did not identify an adverse trend in performance. The inspection methods and frequency of inspections being implemented by the program have been proven effective in detecting aging effects including change in material properties, cracking, hardening and loss of strength, shrinkage, and loss of material (spalling, scaling, corrosion). Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fire Protection program are performed to identify the areas that need improvement to maintain effective performance of the program. Internal Fire Protection program audits by Exelon Nuclear Oversight and external Fire Protection program inspections by the NRC have indicated that the fire barrier inspection program is effective. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Fire Protection program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Fire Protection program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.17 Fire Water System

Program Description

The Fire Water System aging management program is an existing condition monitoring program that manages the loss of material and flow blockage in air-indoor uncontrolled, air-outdoor, condensation, and raw water environments for water-based fire protection systems that consist of sprinklers, nozzles, fittings, valve bodies, fire pump casings, hydrants, hose stations, standpipes, aboveground and underground piping and piping components, tanks, strainers, and flow devices. Fire Water System component materials consist of carbon steel, ductile iron, stainless steel, galvanized steel, gray cast iron, and copper.

Flow testing, visual inspections, and volumetric examinations are performed to ensure that loss of material due to general, pitting and crevice corrosion, microbiologically influenced corrosion (MIC), or fouling, and flow blockage due to fouling is adequately managed. When PBAPS operating experience has shown no loss of intended function of the in scope SSC due to aging effects, testing and inspections will be conducted on a refueling outage interval as allowed by NUREG-2191, AMP XI.M27, Table XI.M27-1, Fire Water System Inspection and Testing Recommendations.

A review of PBAPS operating experience has revealed instances of recurring internal corrosion in the fire water system piping that is within the scope of the Fire Water System program. Inspections are performed on the fire water piping by non-intrusive volumetric examinations, to ensure that aging effects are managed and that wall thickness is within acceptable limits. Abnormal or unacceptable results are entered into the corrective action program for review and resolution.

External surfaces of underground fire main piping are evaluated for loss of material and cracking with aging effects managed as described in the Buried and Underground Piping and Tanks (B.2.1.28) program. Internal surfaces of underground fire main piping are evaluated for loss of material and cracking with aging effects managed as described in the Internal Coating/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program.

The Fire Water System program does not manage cracking as an aging affect because the Fire Water System does not contain fire water storage tanks or high density polyethylene (HDPE) pipe. The fire main underground cement lined pipe aging effects such as cracking are managed by the Internal Coating/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.29) program.

The Fire Water System program includes replacement or testing of a representative sample of sprinklers before they reach 50 years of service. Fifty-year sprinkler head testing will be conducted using the guidance provided in NFPA 25. Performance of the initial 50-year tests will be determined based on the date of the sprinkler system installation.

The PBAPS design does not include water-based fire protection systems that are normally dry but periodically subject to flow and cannot be drained. Therefore, augmented testing in addition to that specified in NFPA 25 is not required. There are no in scope dry pipe sprinkler systems; and dry pre-action sprinkler systems are nitrogen filled, trip tested dry, and visually inspected for corrosion that could cause flow blockage. Engineering walkdowns were performed to verify proper draining of dry pre-action sprinkler systems and deluge systems.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. The system flow testing, visual inspections and volumetric inspections assure that aging effects are managed such that the system intended functions are maintained. Flow testing results are reviewed and trended to identify degrading trends prior to loss of system function. The program ensures that testing and inspection activities have been performed and documented. Abnormal results are entered into the corrective action program for review and resolution.

Inspections and tests are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. The inspections and tests follow station procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

The program will be enhanced, as noted below, to provide reasonable assurance that the Fire Water System aging effects will be adequately managed during the period of extended operation.

NUREG-2191 Consistency

The Fire Water System aging management program will be consistent with the ten elements of aging management program XI.M27, "Fire Water System", specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends foam system operational discharge tests be performed annually. NFPA 25 Section 11.3.2.6 recommends an operational discharge test to ensure that the discharge patterns from all the open spray devices are not impeded by plugged nozzles or obstructions and to ensure the discharge devices are correctly positioned and are not obstructed. Table XI.M27-1, Note 6, requires that when a discharge test cannot be performed, the nozzles are inspected for proper orientation and tested with air to ensure nozzles are not obstructed. An air test through the auxiliary boiler fuel oil storage tank foam chamber nozzle will not be performed. **Program Element Affected: Detection of Aging Effects (Element 4)**

Justification for Exception

The auxiliary boiler fuel oil storage tank is equipped with a single foam chamber and nozzle with a vapor seal which is not a typical open spray system. The foam chamber discharge nozzle has a large orifice (approximately 1 inch diameter). The fuel oil tank is also equipped with a foam deflector to direct the foam gently down the inside of the tank for efficient foam distribution across the surface of the fuel oil. The foam discharge pattern does not apply in this case. A foam system discharge test to verify foam discharge coverage cannot be performed without contaminating the fuel oil. The supply piping is dry and not wetted unless actuated which reduces internal pipe corrosion. An air test cannot be performed without destroying the vapor seal. Additionally, confined space entry into the fuel oil storage tank to verify air flow from the nozzle would create a confined space safety concern.

The Fire Water System aging management program will be enhanced to perform a one-time inspection of the auxiliary boiler fuel oil storage tank internal foam nozzle and deflector to ensure proper configuration, orientation, and no indication of flow blockage. The one-time inspection is adequate since the nozzle is located in the fuel oil tank that is permanently enclosed and not likely to be disturbed.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Revise flow test procedures to include:

    a. Inspector test flush acceptance criteria for wet pipe sprinkler systems that currently do not include the requirement to record time to flow from the opened test valve.

    b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10 percent reduction in full flow pressure when compared to previously performed tests. An issue report shall be generated in the corrective action program to determine the cause and corrective actions.

    c. If acceptance criteria are not met, at least two additional tests shall be performed. If acceptance criteria are not met during follow-up testing, the test shall be performed on the same system, on the other unit.

Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

2. Perform air flow tests on the hydrogen seal oil and reactor building water curtains every two years to ensure deluge piping and nozzles are unobstructed and there are no flow blockages. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)**

3. Increase the frequency of air flow tests through the standby gas treatment and recombiner system deluge piping and nozzles to every two years to ensure piping and nozzles are unobstructed and there are no flow blockages.

Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

4. Revise procedures to improve guidance for external visual inspections of the in scope sprinkler systems piping and sprinklers at least every two years to inspect for excessive corrosion, loss of material, leaks, and proper sprinkler orientation. Corroded, leaking or damaged sprinklers shall be replaced. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

5. Perform external visual inspections of the in scope above ground fire main piping every two years to identify excessive corrosion, loss of material, leaks, and physical damage. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

6. Perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric wall thickness examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the corrective action program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25 Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:

a. Wet pipe sprinkler systems - 50 percent of the wet pipe sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

c. Deluge systems - Yard transformer deluge systems in scope for license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

7. Perform a one-time volumetric wall thickness inspection, prior to the second period of extended operation, on a sample of the original yard transformer deluge system supply piping that was not replaced during transformer

replacements and is periodically subjected to flow during functional testing. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

8. Revise service water bay inspection procedures to include inspection of the motor driven fire pump intake strainer. **Program Element Affected: Detection of Aging Effects (Element 4)**

9. Perform flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five-year frequency to demonstrate the capability to provide the design pressure at required flow. **Program Element Affected: Detection of Aging Effects (Element 4)**

10. Flush deluge system mainline supply basket strainers until clear, following functional testing of yard deluge systems. **Program Element Affected: Detection of Aging Effects (Element 4)**

11. Perform a one-time inspection of the auxiliary boiler fuel oil storage tank internal foam nozzle and deflector, prior to the second period of extended operation, to ensure proper configuration and orientation and no indication of flow blockage. **Program Element Affected: Detection of Aging Effects (Element 4)**

12. Perform an internal inspection of the auxiliary boiler oil storage tank foam system foam concentrate tank every 10 years to ensure it is free of corrosion, debris, or foreign material that could cause flow blockage, and to ensure there are no cracks or leaks and it is in good condition. **Program Element Affected: Detection of Aging Effects (Element 4)**

13. Revise restoration procedures for the hydrogen seal oil and reactor building water curtain systems to utilize low point drains following control valve actuations to ensure there is no trapped water in the system. **Program Element Affected: Detection of Aging Effects (Element 4)**

14. Revise restoration procedures for the yard transformer deluge systems to utilize low point drains after functional testing. **Program Element Affected: Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Water System program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed for the Fire Water System aging management program, which is a subset of the first license renewal Fire Protection Activities aging management program, in support of preparing the license renewal application for second license renewal. The Fire Protection Activities program is described in UFSAR Section Q.2.9. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program,

which is to identify and address aging effects for water-based fire protection systems such as fire pumps, distribution piping, sprinkler systems, deluge systems, and hose station standpipes, is being effectively implemented in the first period of extended operation.

Information was collected for the period time from 2003 to 2016. The program effectiveness review was comprised of a review of surveillance tests, and issues found in the corrective action program associated with inspections and testing of water-based fire protection systems. In addition, internal Fire Protection program audits by Exelon Nuclear Oversight and external Fire Protection program inspections by the NRC were also reviewed to determine the aging program effectiveness. The review identified that age-related degradation of in scope SSCs is identified and managed through the performance of surveillance test inspections, functional tests, and the corrective action program. Age-related issues identified during the inspections were evaluated and corrected within the corrective action program resulting in effective implementation of this aging management program.

Therefore, the aging management program effectiveness review determined that the program is being implemented in accordance with the Fire Protection Activities program as described in UFSAR Section Q.2.9.

This operating experience provides objective evidence that the surveillance testing, piping inspections, maintenance practices, and corrective action program effectively manage aging effects for water-based fire protection systems such as fire pumps, distribution piping, sprinkler systems, deluge systems, and hose station standpipes to assure that these components will continue to perform their intended functions during the first period of extended operation. Continued aging management of these components in accordance with the Fire Water Systems program assures that intended functions will be maintained during the second period of extended operation.

2. Flow test surveillance data from 2003 to 2015 for flow testing of the Unit 3 reactor feedpump turbine area sprinkler system was reviewed. Pressure drop data from the 2 inch main drain test and timing of the inspectors test flow was reviewed for indications of performance degradation that could be indicative of aging effects such as corrosion buildup, fouling, and flow blockage. During the period, there was essentially no change in the system performance data. The tests demonstrate that system performance data is obtained that would identify degradation due to age-related issues. In 2006, an issue was entered into the corrective action program for a leaking hand valve identified during the test. The valve was subsequently repaired. In 2008, an issue was entered into the corrective action program for a failure of a system flow alarm to print in the main control room during a test. The printer was subsequently repaired.

This example provides objective evidence that the sprinkler flow tests performed in accordance with the Fire Water System program are adequate to identify deficient conditions and correct them prior to loss of intended function.

3. Underground fire main flow test surveillance data from 2004 to 2015 was reviewed. Pressure drop data and actual friction loss data for various fire main sections were reviewed for indications of performance degradation that could

be indicative of aging effects such as corrosion buildup, fouling, and flow blockage. During the period, inconsistent data for specific flow tests was identified, and in 2008 the condition was documented in the corrective action program for investigation by engineering. The investigation identified the likely cause of the inconsistent data was leaking underground fire main isolation valves during the test which changed test setup conditions. As a result, a fire main isolation valve replacement project was initiated and underground fire main isolation valves were replaced to improve system performance and testing accuracy. The next scheduled underground fire main flow test scheduled for 2018 will verify the leaking isolation valves caused the previous inconsistent test results.

This example provides objective evidence that the flow tests performed in accordance with the Fire Water System program are adequate to identify deficient conditions and the corrective action program is effectively used to initiate corrective actions prior to loss of intended function.

4. In October 2006, during periodic fire water system piping preventative maintenance ultrasonic testing, a near minimum wall thickness condition at the elbow downstream of the motor driven fire pump discharge was identified. Routine ultrasonic testing of fire main pipe was previously established for trending purposes due to previously identified recurring internal corrosion on fire main piping. The testing location of the fire main piping was established for routine inspections for trending purposes. The test results were entered into the corrective action program for engineering evaluation. Engineering evaluation of the NDE results concluded the pipe was acceptable for continued operation, however, additional NDE testing of the area to determine the extent of condition and overall piping structural integrity was recommended. The pipe section was replaced based on engineering recommendations prior to loss of system function. The new pipe was tested and placed in service with no additional issues.

This example provides objective evidence that the NDE testing of fire water system piping, and the trending of test results, performed in accordance with the Fire Water System program, are adequate to identify deficient conditions and correct them prior to loss of intended function.

The operating experience relative to the Fire Water System program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including flow blockage, and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fire Water System program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Fire Water System program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Fire Water System program will provide reasonable assurance that the flow blockage and loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.18 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program is an existing condition monitoring program that manages aging effects associated with in scope outdoor aboveground tanks constructed on concrete or soil. PBAPS has no indoor, large volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, and no indoor tanks that sit on, or are embedded in concrete, where specific operating experience indicates that the tank surfaces are periodically exposed to moisture. The scope of this program includes the Unit 2 condensate storage tank, the Unit 3 condensate storage tank, and the common refueling water storage tank. These tanks contain treated water, are constructed of carbon steel, are not insulated, are coated both internally and externally as a preventive measure to mitigate corrosion, and are supported on a concrete or asphalt and sand foundation, such that the bottoms of the tanks are inaccessible for direct visual inspection. Sealant is used at the concrete or asphalt interface with the tank.

The program manages loss of material and loss of coating integrity by conducting periodic internal and external visual inspections on a frequency of 10 years or less. Cracking is not a predicted aging effect due to the carbon steel construction. Visual inspections of sealant and caulking will be supplemented with physical manipulation to detect degradation. Thickness measurements of tank bottoms are conducted to ensure that significant degradation is not occurring. Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions, as defined for visual and ultrasonic inspection techniques. The periodic inspection results are compared to acceptance criteria and include trending to allow corrective action to be taken prior to loss of intended function.

The activities to manage the aging effects for internal coatings are performed in accordance with the recommendations of NUREG-2191, AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks. Inspection intervals will conform with those in NUREG-2191, AMP XI.M42, Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.” The acceptance criteria for tank internal coating inspections are provided in Element 6 of AMP XI.M42. The corrective action program is utilized to document and initiate further evaluations when acceptance criteria are not met.

NUREG-2191 Consistency

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program will be consistent with the ten elements of aging management program XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform an inspection of the sealant at the perimeter of the condensate storage tanks and refueling water storage tank bases for signs of degradation every two years. The visual inspections of sealant and caulking are supplemented with physical manipulation to detect degradation. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

2. Perform a pre-inspection review of the previous two inspections of the internal tank coatings, when available, that includes review of results of inspections and any subsequent repair activities. **Program Element Affected: Monitoring and Trending (Element 5)**

3. Conduct training and qualification of individuals involved in internal coating or lining inspections and evaluating degraded conditions in accordance with an ASTM International standard endorsed in RG 1.54. **Program Elements Affected: Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)**

4. Perform volumetric inspection of Unit 2 and 3 condensate storage tanks, and refueling water storage tank bottoms at least once during the 10-year period prior to the second period of extended operation, and at least once every 10 years during the second period of extended operation. Volumetric inspections are performed at representative sample locations to include 25 one square foot locations or 20 percent coverage conducted in different locations unless the program states the basis for why repeated inspections are conducted in the same location (i.e. previous findings). Additionally, a minimum of 10 of the random one square foot sample locations will be performed within the 30-inch band at the perimeter of the shell. The scope of subsequent examinations may be adjusted based upon the results of previous examinations. **Program Elements Affected: Detection of Aging Effects (Element 4) and Monitoring and Trending (Element 5)**

Operating Experience

The following examples of operating experience provide objective evidence that the Outdoor and Large Atmospheric Metallic Storage Tanks program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed for the Outdoor, Buried, and Submerged Component Inspection Activities aging management program in support of preparing the license renewal application for second license renewal. The purpose of the review was

to verify the Outdoor, Buried, and Submerged Component Inspection Activities aging management program, as described in UFSAR Section Q.2.5, is being effectively implemented to manage aging effects for tanks within the scope of the second period of extended operation, during the first period of extended operation. Pre-period of extended operation (PEO) implementation of aging management programs was assessed by the site aging management program owner as part of a site-wide, license renewal implementation assessment. Pre-PEO implementation was also assessed by an NRC Region I inspection under Inspection Procedure 71003. Inspection results included external surfaces of the condensate storage tanks (CSTs) and enhanced inspections of the refueling water storage tank (RWST) as representative of the condition of the CSTs. The RWST was not in scope for the first license renewal, but was added to scope in 2017 under the provisions of 10 CFR 54.37(b) as a newly identified SSC, due to the tank being credited for supplementing CST inventory for Appendix R and ATWS events, as a result of reanalysis work done during the PBAPS extended power uprate project.

The program effectiveness review included the review of implementing activity results and issues in the corrective action program. This review found that condition of the internal coating of the RWST was acceptable without any rework required. There were instances of external coating flaking and rusting on the Unit 2 CST that were identified during the inspection. The issues were entered into the corrective action program and subsequently repaired.

Based on the review of operating experience, it was determined that the original aging management strategy of inspecting the RWST tank bottom as a surrogate for inspecting the CST tank bottoms should be replaced by periodic UT inspections of the CST tank bottoms. These inspection activities are now being performed in accordance with station procedures. As further described in the operating experience examples below, these inspections have confirmed acceptable CST tank bottom thickness. In addition, the UFSAR Section Q.2.5 description of the CST aging management activities is being updated to reflect that UT inspections of the CST tank bottoms are being periodically performed to provide assurance that the tanks will continue to perform their function throughout the first period of extended operation.

This operating experience provides objective evidence that maintenance practices and the corrective action program effectively monitor and maintain the condition of the condensate storage tanks to assure that these components will be able to continue to perform their intended functions during the second period of extended operation.

2. In November 2014, the Unit 2 CST was drained and an inspection of the internal coatings was performed by a qualified external inspection company. The protective coating system was found to be covered approximately 65 percent with intact blisters. Blister sizes and frequency are measured in accordance with ASTM D 714-09, “Standard Test Method for Evaluating Degree of Blistering of Paint.” Sizes are measured as follows: No. 8, 6, 4 and 2; No. 8 is the smallest blister size and No. 2 is the largest blister size. Frequency is measured as few, medium, medium dense and dense. Blister frequency on the floor is few to medium dense. Blister frequency on the tank

wall was few to dense. Blisters are typical in size and frequency from plate to plate on the tank wall. The majority of blisters are small No. 8 followed by No. 6, No. 4 and No. 2, the largest blister rated in ASTM D 714 Standard. Blisters on the tank floor are smaller and less frequent than on the tank wall. Coating blisters that generally occur in immersion areas are osmotic blisters caused by entrapped solvents or other entrapped contaminants. Solvent entrapment is caused by insufficient ventilation during application and curing of the protective coating. Several blisters were tested by hand to determine if the caps were soft or cracked. Blisters tested were intact, hard and were not cracked when viewed with the unaided eye. Osmotic blistering due to solvent entrapment is considered a common failure mode for solvent based coatings in immersion service environments. The vendor report concluded it was acceptable to return the tank to service with a follow-up inspection required within five years.

In October of 2016, the Unit 2 CST was drained and an inspection of the internal coatings and tank bottom measurements were performed. The internal coatings were determined to be in similar condition to the conditions observed in 2014. The bottom was scanned searching for locations less than the minimum allowable thickness. There were no locations that were identified below the minimum allowable thickness, but there were three locations that were marginally above this value. An evaluation was performed to determine the projected remaining life of the tank bottom at these identified locations. Subsequent inspection and repair activities have been scheduled based upon the corrosion rate margins determined in the evaluation. An action request was entered into the corrective action program to perform a recoat of the internal surface of the Unit 2 CST, which is scheduled to be completed in 2020.

This operating experience provides objective evidence that the results demonstrate the maintenance practices and the corrective action program effectively monitor the CSTs to assure that these components will be able to continue to perform their intended functions.

3. In June 2010, at Exelon's LaSalle County Station, samples of rain water captured in the Unit 1 CST berm were identified to contain tritium. This condition was entered into the corrective action program for evaluation. Subsequent investigations determined the source of the tritium to be the condensate storage tank. No leaks were obvious from visible external tank surfaces and the tank was drained for further inspection. The inspection revealed three locations where corrosion from the underside of the tank caused through-wall leaks. Samples of the tank bottom as well as samples of the sand at the leak locations were removed for chemical and metallurgical analysis. The cause of the corrosion was determined to be attributable to chlorides in the sand. The entire bottom of the tank was volumetrically examined and thinned areas were repaired by welding patch plates over the degraded locations. The LaSalle Unit 2 CST was also drained and examined. Several locations were identified to be degraded and were repaired in the same manner as the Unit 1 CST. Work orders were established to re-inspect the bottoms of both tanks in eight years as well as strengthen the inspection requirement for the caulk that is used to seal the tank perimeter to its foundation to prevent water intrusion to the underside of the tank.

This event resulted in an internal corporate operating experience report that drove additional inspection activities at PBAPS on the in scope tanks, including UT of the tank bottoms. In 2016, 100 percent of accessible surfaces of the Unit 2 CST tank bottom was inspected. Although there were no locations with bottom thickness below the design minimum value, there were three locations that approached the minimum bottom thickness value as a result of corrosion from the underside of the tank. These locations were evaluated under the corrective action program and determined to be acceptable until 2020, when scheduled maintenance activities will include repairs of the above locations and the tank will be recoated internally. In 2015, 100 percent of accessible surfaces the Unit 3 CST tank bottom was inspected. There were no locations approaching or below the design minimum bottom thickness value identified. The 100 percent inspection of the RWST bottom is scheduled to be completed in 2018.

This event demonstrates the effective use of industry operating experience and the corrective action program to identify degraded conditions, perform extent of condition reviews, and take timely corrective action to preserve the ability of the tanks to perform their intended functions.

The operating experience relative to the Outdoor and Large Atmospheric Metallic Storage Tanks program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material and loss of coating or lining integrity. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Outdoor and Large Atmospheric Metallic Storage Tanks program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Outdoor and Large Atmospheric Metallic Storage Tanks program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.19 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in aluminum alloy, carbon steel, cast iron, and stainless steel piping, piping components, and tanks with a fuel oil environment. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil quality is maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Fuel oil analyses that do not meet acceptance criteria are evaluated in accordance with the corrective action program. If analysis of fuel oil indicates biological activity or evidence of corrosion then the need for biocide or corrosion inhibitor addition is evaluated.

The fuel oil tanks within the scope of license renewal are uncoated. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected. At least once during the 10-year period prior to the second period of extended operation the internal surfaces of the fuel oil tanks are visually inspected and volumetrically inspected if evidence of degradation is observed during visual inspection or if visual inspection is not possible. During the second period of extended operation, the tanks are inspected at least once every 10 years. Degradation of tank internal surfaces that does not meet acceptance criteria is evaluated in accordance with the corrective action program. Tank inspection results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the second period of extended operation based on the projected rate of degradation. These activities effectively manage the effects of aging by identifying age-related degradation and maintaining potentially harmful contaminants at low concentrations.

To verify the effectiveness of the Fuel Oil Chemistry program, components will be evaluated for inspection as described in the One-Time Inspection (B.2.1.21) program, to ensure that degradation is not occurring and component intended functions are maintained during the second period of extended operation.

NUREG-2191 Consistency

The Fuel Oil Chemistry aging management program will be consistent with the ten elements of aging management program XI.M30, "Fuel Oil Chemistry" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform periodic internal inspection of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543) at least once during the 10-year period prior to the second period of extended operation, and at least once every 10-years during the second period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected. **Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), and Detection of Aging Effects (Element 4)**

2. Perform periodic (quarterly) removal of water collected at the bottom of the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543). **Program Element Affected: Preventive Actions (Element 2)**

3. Perform receipt testing of new fuel oil for particulate concentration and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040), diesel generator fuel oil storage tanks (0A(B,C,D)T038), and diesel fire pump fuel oil storage tank (00T041). **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

4. Perform periodic (quarterly) sampling and analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the diesel generator fuel oil day tanks (0A(B,C,D)T040). Sampling activities will include a sampling methodology that includes a representative sample from the lowest point in the tank. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

5. Perform periodic (quarterly) sampling and analysis for water and sediment and the levels of microbiological organisms for the diesel generator fuel oil storage tanks (0A(B,C,D)T038). **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

6. Perform periodic (quarterly) sampling and analysis for particulate concentration and the levels of microbiological organisms for the diesel fire pump fuel oil storage tank (00T041) and the diesel fire pump day tank (00T543). **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

7. Perform periodic (quarterly) trending of water and sediment content, particulate concentration, and the levels of microbiological organisms for all fuel oil tanks within the scope of the program. **Program Element Affected: Monitoring and Trending (Element 5)**

8. Evaluate the need for biocide or corrosion inhibitor addition if periodic

testing indicates biological activity or evidence of corrosion. **Program Elements Affected: Preventive Actions (Element 2) and Corrective Actions (Element 7)**

9. Evaluate degradation identified during tank internal inspections against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended function throughout the second period of extended operation based on the projected rate of degradation**. Program Elements Affected: Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Fuel Oil Chemistry program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing fuel oil chemistry aging management activities in support of preparing the license renewal application for second license renewal. The existing program includes activities from the following first license renewal aging management programs, including Lubricating and Fuel Oil Quality Testing Activities, as described in UFSAR Section Q.2.1, and Emergency Diesel Generator Inspection Activities, as described in UFSAR Section Q.2.4. The purpose of the aging management program effectiveness review was to verify the intent of the existing activities, which include sampling and analysis of fuel oil, removal of accumulated water from fuel oil tank bottoms, and inspection of fuel oil tanks for age-related degradation are being effectively implemented in the first period of extended operation.

Operating experience within the corrective action program relative to fuel oil quality activities from 2001 through 2016 was reviewed. The review determined that the sampling and analysis of new and stored fuel oil, removal of water from tank bottoms, and tank internal inspections are effective in identifying detrimental impurities in fuel oil and age-related degradation in storage tank bottoms. Deficiencies identified during the performance of periodic aging management program activities were evaluated in the corrective action program. The sampling and analysis of new and stored fuel oil, removal of water from tank bottoms, and tank internal inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of these aging management programs.

In 2012 (Unit 2) and 2013 (Unit 3), pre-period of extended operation implementation of aging management activities associated with the Lubricating and Fuel Oil Quality Testing Activities and Emergency Diesel Generator Inspection Activities aging management programs was assessed by the site aging management program owners as part of a site-wide, license renewal implementation assessment. Results binders were assembled to support the NRC's 71003, "Post-Approval Site Inspection for License Renewal" inspection. Results for new fuel oil and stored fuel oil sampling and analysis, fuel oil storage tank water removal, and internal inspection of the diesel generator fuel oil storage tanks and diesel generator fuel oil day tanks were included. In 2013 (Unit 2) and 2014 (Unit 3), pre-PEO implementation of these aging management programs was assessed via NRC inspections using inspection procedure 71003. The review encompassed fuel oil quality testing activities and fuel oil tank inspection activities. The inspection report specifically discusses the validation performed for the enhanced activities to fuel oil sampling techniques for the diesel fire pump fuel oil storage tank and diesel generator fuel oil storage tanks. The inspector sampled the revised implementing procedures to confirm that the enhanced activities were properly incorporated. The inspector also reviewed corrective action documents and laboratory testing results to confirm that the enhanced activities were being properly implemented. There were no adverse findings identified during these inspections.

The aging management program effectiveness review determined that aging management activities are being implemented in accordance with the Lubricating and Fuel Oil Quality Testing Activities, as discussed in UFSAR Section Q.2.1, and the Emergency Diesel Generator Inspection Activities, as discussed in UFSAR Section Q.2.4.

This example provides objective evidence that existing aging management program activities are being effectively implemented to manage aging effects associated with a fuel oil environment, and that deficiencies identified during the implementation of the program are entered into the corrective action program for evaluation. Continued implementation of the program will assure that components exposed to fuel oil within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. The diesel generator fuel oil storage tanks were internally inspected by visual and volumetric examination techniques in November 2011 (0AT038), May 2010 (0BT038), February 2013 (0CT038), and May 2012 (0DT038). The inspection of tank 0BT038 did not identify any age-related degradation that exceeded acceptance criteria. The inspection of 0AT038, 0CT038, and 0DT038 identified age-related degradation that exceeded acceptance criteria. The inspection of tank 0AT038 identified localized corrosion measuring 0.125 inch deep. The inspection of tank 0CT038 identified two areas of localized corrosion measuring 0.125 inch and 0.109 inch deep. The inspection of tank 0DT038 identified an area of localized corrosion measuring 0.092 inches deep. These issues were entered into the corrective action program for evaluation. Engineering evaluated these deficiencies against code required minimum wall acceptance criteria using ASME Section VIII methodology. Both internal pressure and external pressure (e.g., earth loads, seismic loads and hydrostatic pressure associated with the buried diesel generator fuel oil storage tanks) were considered. The technical evaluations concluded that the condition of the tanks was acceptable and that they would continue to maintain their intended function until their next scheduled inspection.

Boroscope inspections of the associated day tanks (0AT040, 0BT040, 0CT040, and 0DT040) were also performed. These inspections did not identify any age-related degradation that exceeded acceptance criteria.

This example provides objective evidence that fuel oil tank inspection activities are effective in identifying degraded conditions caused by aging effects, and the corrective action program is effective in evaluating the conditions to determine their impacts to system intended functions.

3. In April 2011, during the performance of routine periodic surveillance, water was found in the bottom of diesel generator fuel oil storage tank 0AT038. A sample was taken and analyzed for the presence of microbiological organism. The sample tested positive for microbiological organisms. Analysis results were entered into the corrective action program for evaluation by chemistry and the engineering system manager. Corrective actions included pumping the water out of the fuel oil tank to minimize the potential for corrosion as a result of the presence of microbiological organisms. Subsequent testing in May 2011 did not identify water in the tank.

This example provides objective evidence that routine periodic surveillance is effective at identifying the presence of contaminants that promote aging effects and that fuel oil analyses that do not meet acceptance criteria are entered into the corrective action program for evaluation and the identification of corrective actions.

The operating experience relative to the Fuel Oil Chemistry program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fuel Oil Chemistry program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Fuel Oil Chemistry program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Fuel Oil Chemistry program will provide reasonable assurance that the loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.20 Reactor Vessel Material Surveillance

Program Description

The Reactor Vessel Material Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron embrittlement of the ferritic reactor pressure vessel (RPV) beltline materials in a reactor coolant and neutron flux environment. The program utilizes surveillance capsule that are located near the inside wall of the RPV beltline region to duplicate the neutron spectrum, temperature history, and neutron fluence of the RPV inner surface. The resulting lead factor allows the surveillance capsules to achieve a neutron fluence exposure earlier than the RPV allowing the surveillance capsules to be withdrawn and tested prior to the RPV reaching the neutron fluence of interest.

PBAPS, Unit 2 and Unit 3 are projected to achieved approximately 70 effective full power years (EFPY) of operation at the end of the second period of extended operation. The Unit 2 and Unit 3 surveillance capsules are mounted on the RPV inner surface and have a 0T fluence lead factor of approximately 0.95 and a 1/4T fluence lead factor of approximately 1.38. The peak reactor vessel neutron fluence of interest for a boiling water reactor is the 1/4T neutron fluence. The material upper-shelf energy (USE) and pressure-temperature limits use the 1/4T neutron fluence and the mechanical properties of tested surveillance capsules. Therefore, to satisfy the recommendation to withdraw and test a capsule with the neutron fluence of between one and two times the peak neutron fluence of interest at the end of the second period of extended operation, a capsule will need to be withdrawn after receiving at least 50.7 EFPY worth of neutron irradiation.

The Unit 2 peak 0T neutron fluence at the end of the second period of extended operation is projected to be 2.23E+18 n/cm^2 (E >1.0 MeV) and the peak 1/4T neutron fluence at the end of the second period of extended operation is projected to be 1.54E+18 n/cm^2 (E >1.0 MeV).

The Unit 2 reactor vessel contains three surveillance capsules containing representative RPV material. One of these capsules was withdrawn during the seventh refueling outage, tested, reconstituted, and re-inserted during the eighth refueling outage. Unirradiated data exists for the capsule material. Unit 2 currently participates in the integrated surveillance program (ISP) defined in BWRVIP-86-R1-A: BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan, and is designated as a host plant. Per BWRVIP-86-R1-A, Unit 2 is scheduled to withdraw capsules in 2018 and 2030. This will leave one capsule to support the second period of extended operation. For the second period of extended operation, the Reactor Vessel Material Surveillance aging management program will be enhanced to withdraw and test a Unit 2 capsule during the second period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the second period of extended operation.

The Unit 3 peak 0T neutron fluence at the end of the second period of extended operation is projected to be 2.14E+18 n/cm^2 (E >1.0 MeV) and the peak 1/4T neutron fluence at the end of the second period of extended operation is projected to be 1.48E+18 n/cm^2 (E >1.0 MeV).

The Unit 3 reactor vessel contains three surveillance capsules containing representative RPV material. One of these capsules was withdrawn during the seventh refueling outage, tested, reconstituted, and re-inserted during the eighth refueling outage, and one capsule was withdrawn but not tested during the seventh refueling outage and re-inserted in the eighth refueling outage. Unirradiated data exists for the capsule material. Unit 3 also currently participates in the ISP defined in BWRVIP-86-R1-A and is designated as a non-host plant. Per BWRVIP-86-R1-A, Unit 3 utilizes information from Duane Arnold Energy Center for plate material, River Bend Station for weld material, and the BWROG Supplemental Surveillance Program (SSP) for both the plate and weld materials. For the second period of extended operation, the Reactor Vessel Material Surveillance aging management program will be enhanced to withdraw and test a Unit 3 capsule during the second period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the second period of extended operation.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the second period of extended operation, and (b) provide adequate dosimetry monitoring during the operational period. A surveillance capsule will be withdrawn and tested from each reactor vessel during the second period of extended operation providing reactor vessel material irradiation embrittlement data and dosimetry monitoring during the second period of extended operation.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper-shelf energy as a function of neutron fluence and irradiation temperature. RPV beltline material test results provide reactor vessel material fracture toughness data for the neutron irradiation embrittlement time-limited aging analyses (TLAAs) (e.g., upper-shelf energy and pressure-temperature limits evaluations). The RPV beltline material surveillance capsules are removed at various exposure intervals for monitoring and trending purposes and in conjunction with the Neutron Fluence Monitoring (B.3.1.2) program. See Section 4.2 of the SLRA for discussion of the TLAAs associated with neutron irradiation embrittlement.

Surveillance capsule are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H and ASTM E 185-82. Any changes to the surveillance capsule withdrawal schedule, including changing the status of standby capsule, must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or in-insertion. Abnormal or unexpected results are entered into the corrective action program for engineering evaluation.

NUREG-2191 Consistency

The Reactor Vessel Material Surveillance aging management program will be consistent with the ten elements of aging management program XI.M31, "Reactor Vessel Material Surveillance" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program elements:

1. Withdraw and test the Unit 2, 120 degree capsule and the Unit 3, 120 degree capsule per the capsule withdrawal schedules below. A technical summary report containing the test results shall be submitted to the NRC per the requirements of 10 CFR Part 50, Appendix H. Any changes to the Reactor Vessel Material Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)**

Peach Bottom Unit 2 Capsule Withdrawal Schedule		
Capsule	**Capsule Lead Factor (0T/¼T)**	**Capsule Withdrawal EFPY**
30°	0.95/1.38	Per BWRVIP-86-R1-A
120°	0.95/1.38	7.53 (actual)
120° Reconstituted	0.95/1.38	60 - 62[(1)]
300°	0.95/1.38	Per BWRVIP-86-R1-A

1. Capsule 120° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.21 EFPY less than plant operating EFPY.

Peach Bottom Unit 3 Capsule Withdrawal Schedule		
Capsule	**Capsule Lead Factor (0T/¼T)**	**Capsule Withdrawal EFPY**
30°	0.95/1.38	7.57 (actual)
30° Reconstituted	0.95/1.38	Spare(1)
120°	0.95/1.38	60 - 62
300°	0.95/1.38	Spare(2)

1. Capsule 30° was withdrawn, tested, and reconstituted after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating EFPY.
2. Capsule 300° was withdrawn after Cycle 7 and re-inserted after Cycle 8, therefore capsule EFPY is 1.41 EFPY less than plant operating EFPY.

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Vessel Material Surveillance program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management program, Reactor Materials Surveillance Program, as described in UFSAR Section Q.1.12, in support of preparing the license renewal application for second license renewal. The purpose of the program effectiveness review was to verify the intent of the existing program, which is to complete surveillance capsule testing and evaluation, prepare for withdrawal of the next scheduled capsules, and document program updates is being effectively implemented during the first period of extended operation. The review determined that the Reactor Materials Surveillance Program is being implemented as described in UFSAR Section Q.1.12 during the first period of extended operation. Administrative issues associated with the management of the program were identified and entered into the corrective action program.

This example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the Reactor Vessel Material Surveillance aging management program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the second period of extended operation.

2. In support of the Reactor Vessel Material Surveillance program, capsules have been withdrawn from PBAPS Units 2 and 3 RPVs, and tested in accordance with 10 CFR Part 50, Appendix H.

In 1987, the Unit 2 capsule located at 120 degrees azimuth was withdrawn and tested in accordance with the capsule withdrawal schedule. The capsule had received 7.53 EFPY of irradiation. The pressure-temperature curves were evaluated and updated as required. After testing, the capsule was reconstituted and re-inserted into the reactor vessel during the next refueling outage.

In 1989, the Unit 3 capsule located at 30 degrees azimuth was withdrawn and tested in accordance with the capsule withdrawal schedule. The capsule had received 7.57 EFPY of irradiation. The pressure-temperature curves were evaluated and updated as required. After testing, the capsule was reconstituted and re-inserted into the reactor vessel during the next refueling outage. During the withdrawal of the capsule located at 30 degrees azimuth, it was noted the capsule located at 300 degrees azimuth was detached from the wall mounting bracket. The capsule located at 300 degrees azimuth was removed, stored in the spent fuel pool, and re-installed in the vessel during the next refueling outage.

This operating experience provides objective evidence that the Reactor Vessel Surveillance program is used to effectively monitor the loss of fracture toughness of the reactor vessel beltline materials due to neutron irradiation embrittlement.

3. In 2003, PBAPS obtained NRC approval to participate in the BWR Vessel and Internals Project Integrated Surveillance Program (ISP), which is currently described in BWRVIP-86-R1-A: BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan. PBAPS Unit 2 is designated as a host plant and is scheduled to withdraw and test capsules in 2018 and 2030. PBAPS Unit 3 is designated as a non-host plant and is aligned with River Bend Station for weld material, Duane Arnold Energy Center for plate material, and the BWROG Supplemental Surveillance Program (SSP) for both weld and plate material. River Bend is scheduled to withdraw and test a capsule in 2025. Duane Arnold withdrew and tested a capsule in 2012. The results of the Duane Arnold capsule were evaluated for PBAPS Unit 3 and no changes to the Unit 3 adjusted reference temperatures (ART) or pressure-temperature curves were required. Duane Arnold is scheduled to withdraw and test their next capsule in 2027.

This operating experience provides objective evidence that participation in the ISP in accordance with the Reactor Vessel Surveillance program is used to effectively monitor the loss of fracture toughness of the reactor vessel beltline materials due to neutron irradiation embrittlement.

The operating experience relative to the Reactor Vessel Material Surveillance program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of fracture toughness due to neutron irradiation embrittlement. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Reactor Vessel Material Surveillance program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Reactor Vessel Material Surveillance program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Reactor Vessel Material Surveillance program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.21 One-Time Inspection

Program Description

The One-Time Inspection aging management program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the second period of extended operation; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the second period of extended operation.

The program includes inspections that are focused on locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. The inspections will include a representative sample of the system population and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. Twenty percent of the population with a maximum sample of 25 constitutes a representative sample size. A technical justification of the methodology used for determining sample size and for selecting components for inspection will be included in the One-Time Inspection Sample Basis Document. The program verifies either that unacceptable degradation is not occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the second period of extended operation.

One-time inspections that do not meet acceptance criteria are evaluated in accordance with the corrective action program. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the corrective action program; however, no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections.

Periodic inspections instead of this program will be used for structures or components with known age-related degradation mechanisms or when the environment in the second period of extended operation is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

This new program will be implemented and inspections will be performed within the 10-year period prior to the second period of extended operation.

NUREG-2191 Consistency

The One-Time Inspection aging management program will be consistent with the ten elements of aging management program XI.M32, "One-Time Inspection" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the One-Time Inspection program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed of the aging management activities that included one-time inspections prior to the first license renewal period of extended operation, in support of preparing the license renewal application for second license renewal. Aging management activities that included one-time inspections performed to meet first license renewal commitments include the Torus Piping Inspection Activities described in UFSAR Section Q.3.1, and the One-Time Inspection Activities described in UFSAR Section Q.3.4. The purpose of the review was to verify the intent of the one-time inspection programs, which was to verify the material condition of selected piping systems, was effectively implemented prior to the first license renewal period of extended operation.

In 2012 (Unit 2) and 2013 (Unit 3), pre-period of extended operation implementation of aging management activities associated with the Torus Piping Inspection Activities and One-Time Inspection Activities aging management programs was assessed by the site aging management program owners as part of a site-wide, license renewal implementation assessment. Results binders were assembled to support the NRC's 71003, "Post-Approval

Site Inspection for License Renewal" inspection. The one-time inspection results associated with treated water, sodium pentaborate, reactor coolant, auxiliary steam, raw water, and waste water environments are summarized below.

- A representative sample of piping in the Unit 2 and Unit 3 torus was inspected to confirm the insignificance of aging effects in carbon steel at the treated water/air interface. The lines inspected included the “J” and “K” main steam safety relief valve discharge piping, HPCI turbine discharge piping, and RCIC turbine discharge piping. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Unit 2 and Unit 3 Fuel Pool Cooling systems to confirm the effectiveness of fuel pool chemistry control activities. These inspections were for the loss of material and cracking in stainless steel, and for the loss of material in carbon steel. The inspections validated that there was no cracking and that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Unit 2 and Unit 3 Standby Liquid Control Systems to confirm the insignificance of aging effects in stainless steel with an internal environment of sodium pentaborate. The inspections validated that there was no cracking and that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Unit 2 and Unit 3 RPV bottom head drains to confirm the insignificance of aging effects in carbon steel with an internal environment of reactor coolant. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Unit 2 and Unit 3 RPV instrumentation vent lines to confirm the insignificance of aging effects in carbon steel with an internal environment of reactor coolant. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Auxiliary Steam System piping to confirm the insignificance of aging effects in carbon steel and copper with an internal environment of auxiliary steam. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed in the Unit 2 and Unit 3 Service Water Systems on carbon steel and copper with an internal environment of raw water.

Although there were no immediate integrity concerns, age-related degradation in carbon steel was identified. Inspection data was entered into the raw water database for continued surveillance. Inspection results were also entered into the corrective action program for evaluation and the identification of extent of condition inspections. Extent of condition inspections were performed and the results were satisfactory.

- Inspections were performed in the Unit 2 and Unit 3 Radiation Monitoring Systems on carbon steel, stainless steel, and copper with an internal environment of raw water. Although there were no immediate integrity concerns, age-related degradation in carbon steel was identified. Inspection data was entered into the raw water database for continued surveillance. Inspection results were also entered into the corrective action program for evaluation and the identification of extent of condition inspections. Extent of condition inspections were performed and the results were satisfactory.

- Inspections were performed in the Unit 2 and Unit 3 Equipment and Floor Drain Systems on carbon steel with an internal environment of waste water. The NDE results satisfied the requirements for the One-Time Inspection Activities aging management program. One of the locations inspected did experience some loss of material. This issue was entered into the corrective action program for evaluation and to establish corrosion rates for the system and the need for extent of condition inspections.

In 2013 (Unit 2) and 2014 (Unit 3), pre-PEO implementation of these aging management programs was assessed via NRC regional inspection using inspection procedure 71003. The inspectors reviewed the license renewal application, safety evaluation report, and the inspection implementation plan and results binders, and discussed the one-time inspection commitments with applicable plant staff and license renewal personnel. The inspectors reviewed a summary of inspection results and the supporting inspection reports. There were no adverse findings identified during these inspections. The inspectors concluded there is reasonable assurance that one-time inspection commitments had been adequately implemented at Peach Bottom.

This example provides objective evidence that one-time inspections were performed to meet commitments for the first license renewal and that identified aging issues were entered into the corrective action program, evaluated, and corrective actions were taken to assure affected components will continue to perform their intended functions during the first period of extended operation.

The operating experience relative to the One-Time Inspection program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the One-Time Inspection program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new One-Time Inspection program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.22 Selective Leaching

Program Description

The Selective Leaching aging management program is a new condition monitoring program that includes a one-time inspection for components exposed to closed cycle cooling water and treated water environments since plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for components exposed to raw water, waste water, and soil environments. Visual inspections supplemented by mechanical examination techniques such as chipping or scraping (for ductile and gray cast iron components) will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste 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 second period of extended operation.

Components in the scope of the Selective Leaching aging management program include piping and piping components, valve bodies, pump casings, heat exchanger components, and other components that are constructed of materials and are located in environments that may be susceptible to selective leaching. Materials susceptible to selective leaching which are in the scope of this program are gray cast iron, ductile iron, and copper alloys containing greater than 15 percent zinc. Copper alloys containing greater than 8 percent aluminum (aluminum bronze) are also susceptible to selective leaching; however, there are no components in the scope of license renewal that are constructed of this material. Environments that promote susceptibility to selective leaching include raw water, closed cycle cooling water, treated water, waste water, and soil.

For the one-time and periodic/opportunistic portions of the program, visual inspections will be conducted on a representative sample of components of each material and environment combination of components. A representative sample consists of three percent of each material and environment population per unit or a maximum of 10 components per population per unit. Additionally, for the periodic/opportunistic portion of the program, two destructive examinations will be performed per population per unit for sample populations with greater than 35 susceptible components, or one destructive examination will be performed per population per unit for sample populations with less than or equal to 35 susceptible components. The number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended for each sample population. Since Peach Bottom is a multi-unit site, a reduced periodic visual inspection sample size of eight components maximum per population per unit will be adopted for sample populations that are not percentage-based. This sample size reduction is acceptable because, for the components in the scope of the periodic program, environmental conditions between the units are similar enough such that the aging effects are not occurring differently. Changes to water chemistry practices and to plant equipment and operating conditions (including power rerates) have been performed on both units at approximately the same time, or within a year of each other for those activities that required outage conditions for implementation. Water chemistry programs monitor various chemistry parameters, and require out-of-spec conditions to be corrected under the corrective action program in a timely manner. Raw water systems for both units draw from the same source, the Susquehanna River. Therefore, a reduced sample size will provide a representative sample of the condition of the plant equipment and the existence of the aging effects involved.

Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions as appropriate. Results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the second period of extended operation based on the projected rate and extent of degradation. The acceptance criteria are: (a) for copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color 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, and (d) the components meet system design requirements such as minimum wall thickness, when extended to the end of the second period of extended operation.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the second period of extended operation, additional inspections will be performed. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections

This new program will be implemented and inspections will be performed within the 10-year period prior to the second period of extended operation.

NUREG-2191 Consistency

The Selective Leaching aging management program will be consistent with the ten elements of aging management program XI.M33, "Selective Leaching" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Selective Leaching program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed for the selective leaching portion of the Selective Leaching program commitments in support of preparing the license renewal application for second license renewal. The first license renewal commitment described in UFSAR Section Q.2.9, Fire Protection Activities, includes a one-time test of a cast iron fire protection component for loss of material due to selective leaching. The purpose of the aging management program effectiveness review was to verify the intent of the existing one-time inspection aging management program, which was to determine the extent of the selective leaching aging mechanism on susceptible fire water system components, was effectively implemented in the first period of extended operation.

The aging management program effectiveness review was comprised of a review of the metallurgical evaluation reports for two cast iron valves that were removed, and the follow-up corrective actions. Two valves were removed in 2008 as part of a plant modification. Metallurgical evaluations were performed in 2011. The evaluation reports concluded that both valves showed evidence of selective leaching on the internal surface of the valve body. The results of these inspections were reviewed under the corrective action program, and it was concluded that the structural integrity of the valves was not compromised. Additional corrective actions included destructive evaluations of other fire protection system valves removed from service and the continuation of fire protection system cast iron valve replacements. Of an original population of approximately 70 valves, half have been replaced. An evaluation was performed to assess the selective leaching, and the selective leaching was determined not to be significant because the structural integrity of the valves was not compromised. It was therefore concluded that sufficient margin exists for continued operation and no additional actions were required.

These results were also reviewed by the NRC in January 2013 during the 71003, "Post-Approval Site Inspection for License Renewal", which was performed prior to Unit 2 entering the period of extended operation. No findings were identified, and it was concluded that this commitment had been appropriately implemented. These results were again reviewed in March 2014 prior to Unit 3 entering the period of extended operation, with the same conclusion documented.

The Selective Leaching program will require periodic inspections for selective leaching to be performed within the 10-year period prior to the second period of extended operation. Cast iron components in the fire protection system will be part of this periodic inspection program.

The program effectiveness review identified that age-related degradation of in scope SSCs was identified through the performance of destructive examinations. Age-related issues were evaluated and addressed within the corrective action program. Therefore, the Fire Protection Activities aging management program was implemented in accordance with the UFSAR Section Q.2.9.

This operating experience provides objective evidence that selective leaching inspections, along with the corrective action program, will effectively monitor in scope SSC's to assure that these components will continue to perform their intended functions, and that appropriate aging management will be performed during the second period of extended operation.

2. In December 2014, a visual examination and a metallurgical analysis were performed on a fire protection system valve and section of underground piping which had been replaced. The visual examination of the pipe section determined that the concrete-lined internal surface and the coated external surface were in excellent condition. A follow-up metallurgical examination of the piping identified minor corrosion products but did not identify selective leaching. The visual examination of the valve determined that the external surface was in good condition, and that the internal surface showed evidence of corrosion. A follow-up metallurgical analysis of the valve internal surface identified the presence of corrosion and selective leaching. These components had already been replaced as part of the fire system valve replacements discussed above. The depth of the selective leaching was similar to what was identified in the valves discussed above, and therefore no additional actions were required. Additionally, metallurgical analyses were performed on a fire plug valve, shut-off valve, and associated piping in June 2001. No selective leaching was identified in these components. These examples provide objective evidence that visual and metallurgical examinations are effective methods for identifying selective leaching.

3. Plant operating experience was reviewed for the time period of 2003 to 2013 to identify occurrences of selective leaching. In addition, the failure analysis database of the Exelon Power Labs (the research facility which performs detailed failure and metallurgical analyses for Exelon nuclear facilities) was researched to determine if selective leaching has been identified for components at Peach Bottom. No occurrences of selective leaching were identified for components in closed cycle cooling water or treated water environments.

This review provides objective evidence that selective leaching has not been identified in these environments at Peach Bottom, and therefore, the use of one-time testing for selective leaching in closed cycle cooling water and treated water environments is appropriate.

The operating experience relative to the Selective Leaching program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting the loss of material aging effect. Appropriate guidance for evaluation, repair, or replacement will be provided for locations where degradation is found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Selective Leaching program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Selective Leaching program will provide reasonable assurance that the loss of material aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.23 ASME Code Class 1 Small-Bore Piping

Program Description

The ASME Code Class 1 Small-Bore Piping aging management program is a new conditioning monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. The program includes measures to verify that degradation is not occurring; thereby either confirming that there is no need to further manage aging-related degradation or validating the effectiveness of existing programs and practices for the second period of extended operation.

The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking of ASME Code Class 1 small-bore piping or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) for plants that have experienced cracking of ASME Code Class 1 small-bore piping and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking.

Review of PBAPS operating experience identified two failures of ASME Code Class 1 small-bore piping socket welds on Unit 3; one in 2005, and one in 2017. Analysis using destructive examination methods determined that the failures were caused by weld fabrication defects and developed into through wall leaks due to fatigue. The failures were effectively mitigated by implementing an improved weld design that is more resistant to fatigue. The improved weld design was implemented on the failed welds and several other Unit 3 socket welds that were replaced as a result of extent of condition reviews. There have been no Class 1 small-bore piping cracking or leak events on Unit 3 butt welds or on Unit 2 socket welds or butt welds.

Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. Because more information can be obtained from a destructive examination than from a nondestructive volumetric examination, any weld that is destructively examined can be credited as equivalent to having volumetrically examined two welds. If cracking is revealed by a one-time inspection, the condition will be entered into the corrective action program and additional one-time inspections will be performed for the population of welds (butt welds or socket welds) that have experienced cracking in accordance with ASME Section XI, Subarticle IWB-2420; and periodic inspections will be performed in accordance with NUREG-2191, Table XI.M35-1, Category C. The following table provides a summary of the number of one-time inspections required for Unit 2 and Unit 3 butt welds and socket welds:

Unit	Type of Weld (Butt or Socket)	Category per Table XI.M35-1	Percent/Number Requiring One-Time Inspection	Number of Welds in the Population	Number of One-Time Weld Inspections Required
2	Butt Welds	A	3% up to 10	89	3
2	Socket Welds	A	3% up to 10	More than 1000	10
3	Butt Welds	A	3% up to 10	90	3
3	Socket Welds	B	10% up to 25	More Than 1000	25

This new program will be implemented and one-time inspections will be performed within the six-year period prior to the second period of extended operation.

NUREG-2191 Consistency

The ASME Code Class 1 Small-Bore Piping aging management program will be consistent with the ten elements of aging management program XI.M35, "ASME Code Class 1 Small-Bore Piping" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Code Class 1 Small-Bore Piping program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. A comprehensive review of plant-specific PBAPS Unit 2 and Unit 3 operating history from 1974 until 2017 was performed to identify all issues of cracking or leaks in ASME Code Class 1 small-bore piping (less than 4 inch NPS and greater than or equal to 1 inch NPS). Since any 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 all License Event Reports (LERs) for PBAPS Units 2 and 3 was performed using keyword searches (crack, leak, Class 1, and reactor coolant). The review identified one Class 1 small-bore piping crack and leak at a socket weld on Unit 3 in 2005 (LER 03-05-03), as discussed in Operating Experience Example 2. There was another Class 1 small-bore piping crack and leak at a socket weld on Unit 3 in 2017 (LER 3-17-001) that is discussed in Operating Experience Example 3. There have been no other Class 1 small-bore piping cracking or leak issues

during the Unit 3 operating history. There have been no Class 1 small-bore piping cracking or leak issues during the Unit 2 operating history.

This example provides objective evidence that ASME Code Class 1 small-bore piping is in excellent material condition and that the measures in place to prevent cracking of Class 1 small-bore piping including the design of the plant piping systems to prevent cracking caused by fatigue, and effective water chemistry controls to mitigate stress corrosion cracking, have been effective.

2. On Unit 3, in 2005, a crack and resulting leak was identified on a Class 1, 1 inch NPS stainless steel socket weld at a coupling in the below seat piping portion of the equalizing line around the Residual Heat Removal (RHR) system testable check valve (AO-3-10-46A), located inside primary containment. The issue was entered into the corrective action program where failure analysis, an extent of condition review and resulting volumetric (UT) examinations, and repair using an improved weld design was performed. Failure analysis identified several areas of lack of fusion weld at the socket weld root that significantly reduced the strength of the weld and its resistance to fatigue. The largest lack of fusion area was approximately 40 percent of the design weld thickness that extended 0.340 inches around the weld. The crack initiated at the largest lack of fusion site in the weld root and propagated into a through wall crack due to fatigue.

Review of work history revealed that the affected socket weld joint was installed during the Unit 3 Reactor Recirculation and RHR system pipe replacement project between 1987 and 1989. During the pipe replacement project, the RHR injection and shutdown cooling return piping upstream and downstream of AO-3-10-046A was replaced, and AO-3-10-046A was reused. The equalizing piping was cut away and later reinstalled using two socket welded couplings. The equalizing piping configuration includes 1 inch couplings in the above seat and below seat piping a few inches below the valve body. The configuration of the above and below seat connections on AO-3-10-46A is such that the centerline distance between the 1 inch connections is 4.5 inches. With the couplings installed at the same distance from the valve body, the edge-to-edge distance between the two couplings is approximately 2.7 inches. Contributing factors to the weld fabrication defects at the coupling in the below seat piping included less than ideal working conditions during the pipe replacement project and the limited access for welding at the couplings created by the unique piping configuration. The largest lack of fusion site was located on the side of the joint facing the adjacent coupling, which would be expected given the limited access created by the piping configuration.

The following factors were applied in identifying the extent of condition:

- Stainless steel, small-bore piping within the ASME Class 1 boundary,
- Piping connected to process piping components that were disturbed during the Unit 2 or Unit 3 pipe replacement projects, and
- Piping configurations (evident via drawing review) that resulted in limited access to socket weld joints.

The extent of condition review identified the socket welds at the coupling in the above seat portion of the equalizing line around Unit 3 AO-3-10-46A (two welds), and the welds at both couplings in the equalizing lines around the Unit 3 "B" loop RHR system testable check valve (AO-3-10-46B) and the Unit 2 "A" and "B" loop RHR system testable check valves (AO-2-10-46A and AO-2-10-46B) (two couplings and four welds at each valve), as susceptible to the same causes, and therefore required UT examination.

The results of the UT examinations performed as a result of the extent of condition review were as follows:

- On Unit 3, an indication was identified in the upper socket weld at the coupling in the above seat portion of the equalizing line around AO-3-10-46A.
- On Unit 3, indications were identified in all four socket welds at the couplings in the equalizing line around AO-3-10-46B.
- On Unit 2, there were no indications identified in any of the socket welds at the couplings in the equalizing lines around AO-2-10-46A and AO-2-10-46B, performed during the refueling outage in 2006.

The resulting repairs included replacement of both couplings and the associated socket welds in the equalizing lines around AO-3-10-46A and AO-3-10-46B with welds having a 2:1 axial leg ratio to mitigate the contributing cause of fatigue. In each case the socket weld at the next fitting away from the check valve was also replaced with a 2:1 axial leg ratio weld. A 2:1 axial leg ratio weld reduces the stress intensity factor by 33 percent compared to a 1:1 axial leg ratio weld, increasing the strength of the weld and its resistance to fatigue failure.

This example provides objective evidence that the corrective action program was used effectively to identify the cause(s) of the weld failure, identify the population of welds within the extent of condition, and implement corrective actions to mitigate the age-related cause of the failure. This example also demonstrates that UT examination of socket welds performed to address the extent of condition was effective in identifying indications in those welds.

3. On Unit 3, in 2017, a Class 1 small-bore piping failure involved a crack and resulting leak from a 1 inch NPS stainless steel socket weld at a tee fitting in the instrument sensing line from the "B" loop reactor recirculation pump discharge piping, located inside primary containment. The issue was entered into the corrective action program where failure analysis, repair using an improved weld design, and extent of condition review were performed.

Failure analysis identified several areas of lack of fusion at the socket weld root that reduced the strength of the weld and its resistance to fatigue. The crack initiated at a lack of fusion area at the weld root that was 0.03 inches deep, approximately 15 percent through wall, that extended 0.14 inches around the weld, and propagated into a through wall crack due to fatigue. The characteristics of the crack were typical of those caused by high cycle fatigue. The welds that failed and five other socket welds associated with the sensing line with the failure were made with a 2:1 axial leg ratio to mitigate the fatigue aging effect by increasing the strength of the welds and their resistance to fatigue failure. The length of the sensing line was also shortened to reduce the susceptibility for fatigue.

Review of work history revealed that the affected socket weld joint was installed during the Unit 3 Reactor Recirculation and RHR system pipe replacement project between 1987 and 1989. A preliminary extent of condition review identified the following Unit 3 locations where the piping was reinstalled during the Unit 3 Reactor Recirculation and RHR system pipe replacement project and the support configuration was such that the piping is susceptible to vibration fatigue:

- The instrument sensing line from the "A" loop reactor recirculation pump discharge piping. The length of the sensing line was shortened to reduce susceptibility for fatigue and two welds were replaced with welds having a 2:1 axial leg ratio during the 2017 refueling outage.
- The "A" loop reactor recirculation pump seal purge vent line. The length of the sensing lines was shortened to reduce susceptibility for fatigue and two welds were replaced with welds having a 2:1 axial leg ratio during the 2017 refueling outage.

A more comprehensive extent of condition review was later performed to identify all socket welds affected by the Reactor Recirculation and RHR system pipe replacement projects on Units 2 and 3 that are subjected to vibration and located closest to the branch connection or source of vibration. Socket welds identified as susceptible to vibration fatigue will be mitigated by improving the weld design to 2:1 axial weld ratio during the next refueling outage.

This example provides objective evidence that the corrective action program was used effectively to identify the cause(s) of the weld failure, identify the population of welds within the extent of condition, and implement corrective actions to mitigate the age-related cause of the failure.

The operating experience relative to the ASME Code Class 1 Small-Bore Piping program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Code Class 1 Small-Bore Piping program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the ASME Code Class 1 Small-Bore Piping program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new ASME Code Class 1 Small-Bore Piping program will provide reasonable assurance that the cracking aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.24 External Surfaces Monitoring of Mechanical Components

Program Description

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that will consist of visual inspections that are performed during system inspections and walkdowns. The program will consist of periodic visual inspections of metallic and elastomeric components such as piping, piping components, ducting, ducting components, HVAC closure bolting, elastomeric components, and other components within the scope of license renewal. There are no cementitious components in the scope of this program. The program will manage aging effects through visual inspection of external surfaces for evidence of loss of material and cracking of metallic components, as well as loss of material, cracking, and hardening and loss of strength for elastomers, loss of preload for HVAC closure bolting, and reduced thermal insulation resistance. Visual inspections will be augmented by physical manipulation to confirm the absence of hardening and loss of strength of elastomers. This program does not manage reduction of heat transfer due to fouling for heat exchanger surfaces exposed to air. This aging effect for this component type and environment will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program.

Inspections will be performed by personnel qualified in accordance with station procedures and programs to perform the specified task. When required by the ASME Code, inspections will be conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests will follow station procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. The inspections are capable of detecting age-related degradation and will be performed at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Evaluations of as-found conditions will include confirmation that intended functions will be maintained given the projected degradation rate and the timing of subsequent inspections. Additionally, sample selection, size and frequency will be confirmed to maintain intended functions as applicable based on the projected degradation rate. Acceptance criteria will be defined to ensure that the need for corrective actions will be identified before loss of intended functions. For quantitative analyses, the required minimum wall thickness to meet the applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color and other indicators will be addressed.

Reduced thermal insulation resistance due to moisture intrusion, associated with insulation that is jacketed, will be managed by visual inspection of the condition of the jacketing when the insulation has an intended function to reduce heat transfer from the insulated components. Component surfaces that are insulated and exposed to condensation (because the component is operated below the dew point), and insulated outdoor components, will be periodically inspected every 10 years during the subsequent period of extended operation by removing insulation and inspecting the metal surfaces for evidence of corrosion and cracking. 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. A minimum of 20 percent of the piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve body) will be inspected after the insulation is removed. Alternatively, any combination of a minimum of twenty-five 1-foot axial length sections and components for each material type will be inspected. Loss of material due to boric acid corrosion is not an applicable aging effect for Peach Bottom.

This program does not manage cracking due to stress corrosion cracking (SCC) or loss of material in aluminum and stainless steel components exposed to aqueous solutions and air environments containing halides. As discussed in SLRA Sections 3.1.2.2.16, 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.2, 3.3.2.2.4, 3.4.2.2.3, 3.2.2.2.8, 3.3.2.2.8, 3.4.2.2.7, 3.2.2.2.10, 3.3.2.2.10, and 3.4.2.2.9, a review of plant operating experience has not identified the existence of these aging effects in aluminum and stainless steel components in these environments. Additionally, the specific aluminum alloys of components within the scope of this program were either evaluated to be non-susceptible to cracking or to be in environments which do not contain halides per the guidance in NUREG-2192. Therefore, one-time inspections will be performed for these material, environment, and aging effect populations under the One-Time Inspection (B.2.1.21) program to verify that these aging effects are not applicable. If cracking or loss of material is identified during the one-time inspections, periodic inspections will be performed under the appropriate aging management program, which may include this program, as applicable.

This new program will be implemented prior to the second period of extended operation.

NUREG-2191 Consistency

The External Surfaces Monitoring of Mechanical Components aging management program will be consistent with the ten elements of aging management program XI.M36, "External Surfaces Monitoring of Mechanical Components" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the External Surfaces Monitoring of Mechanical Components program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. A system manager walkdown of the portions of the drywell ventilation system inside the drywell was performed on Unit 2, in 2016 during the fall refueling outage. The inspection identified several areas of insulation on chilled water piping that required repair. These issues were entered into the corrective action program, and repaired prior to the end of the outage.

This example provides objective evidence that system manager walkdowns are an appropriate method for monitoring the condition of external surfaces including insulation, that the refueling cycle inspection frequency is appropriate for inspecting components that are not accessible while the plant is running, and that use of the corrective action program is an effective process for correcting identified deficiencies.

2. A system manager walkdown of the emergency cooling tower in 2010 identified deteriorated coating and minor corrosion on the “C” tower sparger piping and piping supports. This issue was entered into the corrective action program. The affected areas were cleaned and recoated under a work order during the next system work window the following year.

This example provides objective evidence that system manager walkdowns are effective in identifying loss of material, and that the use of the corrective action program is an effective process for correcting identified deficiencies.

3. During maintenance on a pump structure ventilation system fan in 2006, the associated fan discharge flex joint was observed to be degraded and brittle due to wear. This issue was entered into the corrective action program, and the material was replaced.

This example provides objective evidence that visual inspections and physical manipulation of elastomers are effective in identifying elastomer degradation, and that the use of the corrective action program is an effective process for correcting identified deficiencies.

The operating experience relative to the External Surfaces Monitoring of Mechanical Components program indicates that the inspection methods being implemented by the program have been proven effective in detecting the applicable aging effects. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the External Surfaces Monitoring of Mechanical Components program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new External Surfaces Monitoring of Mechanical Components program will provide reasonable assurance that the applicable aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material and hardening and loss of strength of elastomeric materials. Reduction of heat transfer will also be managed. This program will consist of visual inspections of internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other mechanical components. Applicable environments include condensation, closed cycle cooling water, diesel exhaust, fuel oil, lube oil, raw water, treated water, and waste water. Visual (VT-1) or surface examinations will be performed to detect cracking of stainless steel components exposed to diesel exhaust. Except for hardening and loss of strength of elastomers, aging effects associated with components within the scope of the Open-Cycle Cooling Water System (B.2.1.11) program, Closed Treated Water Systems (B.2.1.12) program, and Fire Water System (B.2.1.17) program will not be managed by this program. Loss of material due to recurring internal corrosion on the drain pans of the HPCI, RCIC, Core Spray and RHR pump room unit coolers will be managed by this program.

Internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the second period of extended operation a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population per unit are typically inspected. However, since PBAPS is a two-unit site, this maximum number will be reduced to 19 components per population per unit where the sample size is not based on a percentage of the population. This is acceptable because design, operating, and environmental conditions between the units are similar enough such that the aging effects are not occurring differently. Changes to water chemistry practices and to plant equipment and operating conditions (including power rerates) have been performed on both units at approximately the same time, or within a year of each other for those activities that required outage conditions for implementation. Water chemistry programs monitor various chemistry parameters, and require out-of-spec conditions to be corrected under the corrective action program in a timely manner. Raw water systems for both units draw from the same source, the Susquehanna River. The emergency diesel generators (EDGs) are common plant equipment that support both operating units. EDG run times are managed such that wear and aging is distributed evenly between them. Therefore, a reduced maximum sample population size will provide a representative sample of the condition of the plant equipment and the existence of the aging effects involved.

Sample selection will consider component susceptibility to aging due to factors such as time in service and severity of operating conditions. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment. Additionally, similar environments can be combined into a larger population provided that the inspections occur on components located in the most severe environment. Opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

Additionally, in accordance with NUREG-2191, AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks", loss of coating integrity for certain internally coated tanks in the Radwaste and Reactor Water Cleanup Systems will be performed in this program. This is acceptable because the intended function of these tanks is leakage boundary, and loss of coating integrity would not result in downstream effects of in scope components. Additionally, the internal environments of these tanks are treated water, raw water (potable), and condensation, which do not contain chemical compounds that could cause accelerated corrosion or promote MIC. These tanks are not subject to galvanic corrosion, and their design does not credit the internal coating.

This program does not manage cracking due to stress corrosion cracking (SCC) or loss of material in aluminum and stainless steel components exposed to aqueous solutions and air environments containing halides. As discussed in SLRA Sections 3.1.2.2.16, 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.8, 3.3.2.2.8, and 3.4.2.2.7, a review of plant operating experience has not identified the existence of these aging effects in stainless steel and aluminum components in these environments. Therefore, one-time inspections will be performed for these material, environment, and aging effect populations under the One-Time Inspection (B.2.1.21) program to verify that these aging effects are not applicable. If cracking or loss of material is identified during the one-time inspections, periodic inspections will be performed under the appropriate aging management program, which may include this program as applicable.

Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures which include inspection parameters such as lighting, distance, offset, and surface conditions. Evaluations of as-found conditions will include confirmation that intended functions will be maintained given the projected degradation rate and the timing of subsequent inspections. Additionally, sample selection, size and frequency will be confirmed to maintain intended functions as applicable based on the projected degradation rate. Acceptance criteria will ensure that the component will meet its intended function until the next inspection or the end of the second period of extended operation. For quantitative analyses, the required minimum wall thickness to meet the applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color and other indicators will be addressed.

Additional inspections will be conducted if one of the inspections (i.e., opportunistic or periodic) does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. If second inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections.

This program will be implemented prior to the second period of extended operation.

NUREG-2191 Consistency

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program will be consistent with the ten elements of aging management program XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the Ventilation System Inspection and Testing Activities described in UFSAR Section Q.2.3, the Emergency Diesel Generator Inspection Activities related to the aging management of emergency diesel system flexible hoses, diesel exhaust silencers, and diesel starting air system receivers described in UFSAR Section Q.2.4, and the HPCI and RCIC Turbine Inspection Activities related to the aging management of the turbine casings described in UFSAR Section Q.2.10. This review was performed in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of these existing aging management activities, which is to manage change in material properties for ventilation flex connections and plenum door seals, loss of material in emergency diesel system starting air receiver and diesel exhaust silencers, change in material properties of emergency diesel system hoses, and loss of material of the HPCI and RCIC turbine casings is being effectively implemented in the first period of extended operation. The aging management program effectiveness review included a review of the results of the surveillances and preventive maintenance tasks that are being performed to

manage the applicable aging effects. The review also included relevant issues identified in the corrective action program. Information was collected for the time period from 2003 to 2016.

Activities to check elastomeric components such as emergency diesel system hoses and ventilation system flex hoses and plenum door seals routinely monitor the condition of these components and replace them as needed, based on inspection results. Activities to clean and inspect metallic components such as the turbine casings and diesel air start and exhaust systems components are routinely performed to maintain material condition. The review identified that age-related degradation that is identified through the performance of these activities is evaluated and corrected through the corrective action program, resulting in effective implementation of these aging management activities. Therefore, the aging management program effectiveness review determined that these activities are being implemented in accordance with UFSAR, Sections Q.2.3, Q.2.4, and Q.2.10.

This operating experience provides objective evidence that the results demonstrate that these aging management activities effectively monitor the associated SSCs to assure that these components will be able to continue to perform their intended functions and that appropriate aging management will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that the aging management activities have effectively managed loss of material of metallic components and change in material properties of elastomers.

2. In 2011, maintenance personnel identified corrosion on the floor of the inside plenum on the Unit 2 “D” RHR room unit cooler fan during a preventive maintenance task. This issue was entered into the corrective action program, and repaired during a subsequent system maintenance window.

This example provides objective evidence that performing opportunistic inspections is an effective method for identifying degraded conditions, and that the corrective action program is an effective tool for correcting and resolving identified issues.

3. In 2002, an exhaust leak was found on the E2 diesel during a test run following the diesel overhaul. The leak was identified by the observation of a puff of smoke. This issue was entered into the corrective action program for follow-up actions. The cause of the leak was determined to be a crack in the bellows of an expansion joint, and the expansion joint was replaced.

This example provides objective evidence that visual inspections are an effective method to monitor for degradation of components in the diesel exhaust environment, and that the corrective action program is effective for evaluating degraded conditions which are identified.

4. A review of PBAPS operating experience over a 15-year period has revealed recurring internal corrosion (RIC) on the drain pans of the HPCI, RCIC, Core Spray and RHR pump room unit coolers, which are galvanized steel components in a waste water environment. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will

include targeted inspections of this component population to ensure that the applicable aging effects are effectively managed during the second period of extended operation. RIC has occurred in these locations because of the accumulation of water in the pans due to their drains becoming clogged. Preventive maintenance tasks will be performed on a five-year frequency to inspect and clean the drains if required, and to inspect the drain pans for loss of material and repair as necessary. This will address both the cause and the effect of RIC in this application.

This example provides objective evidence that plant operating experience is reviewed for recurring internal corrosion, and appropriate actions are incorporated into aging management programs.

The operating experience relative to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, flow blockage, hardening and loss of strength, loss of material, and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.26 Lubricating Oil Analysis

Program Description

The Lubricating Oil Analysis aging management program is an existing condition monitoring program that provides monitoring of oil condition to manage loss of material and reduction of heat transfer in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling and analysis activities identify specific wear products and verify the contamination levels (primarily water and particulates) and the physical properties of lubricating oil are maintained within acceptable limits consistent with vendor or industry guidelines to ensure that component intended functions are maintained.

The program includes sampling, analyses, and trending activities which preserve an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil sampling and analysis activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. Oil analyses that do not meet acceptance criteria are evaluated in accordance with the corrective action program. The contaminant levels are trended in the program’s database, and recommendations are made when adverse trends are observed, which could include in-leakage and corrosion product buildup.

The program applies monitoring methods that are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent degradation that would affect a component’s ability to perform its intended function.

To verify the effectiveness of the Lubricating Oil Analysis program, selected components will be inspected as described in the One-Time Inspection (B.2.1.21) program, to ensure that degradation is not occurring and component intended functions are maintained during the second period of extended operation.

NUREG-2191 Consistency

The Lubricating Oil Analysis aging management program is consistent with the ten elements of aging management program XI.M39, "Lubricating Oil Analysis," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Lubricating Oil Analysis program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing lubricating oil analysis aging management activities in support of preparing the license renewal application for second license renewal. The existing program includes activities from the first license renewal aging management program, Lubricating and Fuel Oil Quality Testing Activities, as described in UFSAR Section Q.2.1. The purpose of the aging management program effectiveness review was to verify the intent of the existing activities, which is to ensure 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 this program, is being effectively implemented in the first period of extended operation.

Operating experience within the corrective action program relative to lubricating oil aging management activities from 2001 through 2016 was reviewed. The review concluded that the program has maintained oil system contaminants within acceptable limits through periodic sampling, analysis and trending, and comparing the analytical results to pre-determined limits that trigger corrective actions such as filtering or oil replacement. The program effectiveness review verified that the program is being implemented as described in UFSAR Section Q.2.1.

Pre-period of extended operation implementation of the Lubricating and Fuel Oil Quality Testing Activities program was assessed by the site aging management program owner as part of a site-wide, license renewal implementation assessment. As documented in the Lubricating Quality Testing Activities results binder, completed lubricating oil sampling activities associated with the High Pressure Coolant Injection, Reactor Core Isolation Cooling, Emergency Diesel Generator, Core Spray, and High Pressure Service Water systems were reviewed. The assessment of these activities concluded that the program effectively maintains oil system contaminants within acceptable limits through periodic sampling and analysis, trending, and by comparing the analytical results to pre-determined acceptance criteria. Results that were outside of the acceptance criteria were entered into the corrective action program to evaluate the condition and implement corrective actions such as filtering or draining, flushing, and refilling components containing lubricating oil to maintain oil contaminants within acceptable limits.

In January 2013, the results binder was reviewed by the NRC during the 71003, "Post-Approval Site Inspection for License Renewal" inspection to ensure that Lubricating and Fuel Oil Quality Testing Activities program commitments were being properly implemented prior to entering the period of extended operation. No issues with the implementation of the program were identified by the NRC during the inspection.

In March 2014, an NRC integrated inspection was performed at PBAPS.

Lubricating oil analysis activities associated with the Unit 2 “B” HPSW pump motor were reviewed as part of the assessment of maintenance effectiveness. No findings were identified with these activities.

This example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the program will effectively manage aging prior to failure or loss of intended function during the second period of extended operation.

2. In March 2011, quarterly oil analysis results for the E3 emergency diesel generator crankcase oil indicated an increase in wear particle concentration (WPC) from the previous sample. All other oil analysis results (e.g., viscosity, moisture) were acceptable and trending steady. Elemental spectroscopy was performed and the results were acceptable and trending steady. Vibration data was reviewed to determine whether the increased WPC was the result of component wear. Vibration data was acceptable. The component maintenance organization recommended trending the crankcase oil analysis results to determine if there was an increasing wear trend. Samples from May 2011 and August 2011 were trended and evaluated. WPC from both samples were within acceptable range. All other parameters were acceptable and trending steady. Based on these results, the E3 emergency diesel generator crankcase oil was determined to be acceptable and trending was no longer required.

This example provides objective evidence that the program provides for the periodic sampling, analysis, and trending of data for monitoring wear rates and the physical properties of oil in machinery. The program facilitates the predictive maintenance of equipment and effectively manages aging prior to failure or loss of intended function.

3. In March 2012, oil analysis results for the Unit 2 RCIC pump bearings indicated that the wear particle concentration (WPC) and elemental spectroscopy for iron decreased after previous oil flushes but was still higher than expected. The component maintenance organization recommended that the inboard and outboard pump bearings be drained and flushed to lower the WPC and iron during the upcoming RCIC turbine minor inspection in November 2012. Following draining and flushing, monitoring and trending of oil analysis results continued for both bearings. In June 2014, the bearings were again drained and flushed due to high WPC and iron. As of August 2016, WPC and iron remain at acceptable levels with no adverse trend.

This example provides objective evidence that the program provides for the periodic sampling, analysis, and trending of data and is capable of recognizing a potential condition adverse to quality and implementing appropriate corrective actions prior to failure or loss of intended function.

4. In December 2011, a self-assessment of plant lubricating oil activities was conducted. One of the objectives of the assessment was the verification of lubricating oil sampling execution via the work management process. The assessment concluded that sampling performed during routine preventive maintenance walk-arounds and sampling performed during surveillance testing

are adequately scheduled and executed by the work management process.

This example provides objective evidence that the program manager critically assesses program performance to identify actions that support continuous improvement.

The operating experience relative to the Lubricating Oil Analysis program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Lubricating Oil Analysis program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Lubricating Oil Analysis program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing Lubricating Oil Analysis program provides reasonable assurance that the loss of material and reduction of heat transfer aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.27 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

Program Description

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is an existing condition monitoring program that includes periodic inspection, testing, monitoring, and analysis of test coupons of the Boralcan™ (Rio Tinto Alcan Composite) neutron-absorbing material in the spent fuel storage racks to assure that the required five percent sub-criticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material for visual appearance, dimensional measurements, weight, geometric changes (e.g., bubbling, blistering, corrosion, pitting, cracking, and flaking), and boron areal density as observed from coupons, to monitor for reduction of neutron absorbing capacity, loss of material, and change in dimension.

The Monitoring of Neutron-Absorbing Materials Other than Boraflex aging management program monitors changes in physical characteristics of the material in the spent fuel storage racks through visual inspections, dimensional measurements, neutron-attenuation testing, and weight and specific gravity measurements of test coupons. The test coupons are made from the same material as used for the rack inserts. The coupon program simulates the various conditions of service that the inserts may be exposed to, including general corrosion, galvanic corrosion, stresses at the bend of the insert, and service duty wear. The coupons locations and the locations of freshly discharged fuel assemblies are managed such that the irradiated condition of the coupons bounds that of the neutron-absorbing material in the spent fuel racks. Results of each coupon surveillance are documented and retrievable. Acceptance criteria thresholds are established as indicators of potential adverse trends in the condition of the neutron-absorbing material to ensure corrective actions are taken prior to compromising the five percent sub-criticality margin as contained within the spent fuel pool criticality analysis.

NUREG-2191 Consistency

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is consistent with the ten elements of aging management program XI.M40, "Monitoring of Neutron-Absorbing Materials Other Than Boraflex" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. The spent fuel storage racks that are currently installed in the Peach Bottom Units 2 and 3 spent fuel pools were originally equipped with Boraflex as the neutron-absorbing material. Refer to the first Peach Bottom LRA and SER (NUREG-1979) for further information. Condition monitoring of the Boraflex material was performed by periodic testing and analysis, and revealed degradation over time. Corrective actions were taken in response to monitoring results, which included in-situ areal density measurements, fuel pool criticality analyses, and administrative limitations on use of cell locations as short-term actions. The long-term corrective action was to install an alternate neutron-absorbing material. A modification was performed to install Netco inserts, which utilize Boralcan™ (Rio-Tinto Alcan composite) as the neutron-absorbing material, in each fuel storage rack cell location. This modification was performed over several years, beginning with the most limiting storage cell locations, and was completed in 2016 for both spent fuel pools. A license amendment was issued to allow the use of the inserts in the spent fuel storage racks for the purpose of criticality control in the spent fuel pools (ML13114A929). As a result, Boraflex is no longer credited as the neutron-absorbing material. A condition monitoring program is in place for the new Boralcan™ material. This example provides evidence that monitoring and evaluation of test results and the corrective action program were effective for identifying, monitoring, and evaluating degraded conditions, and implementing corrective actions in response to degraded conditions.

2. The first set of Boralcan™ coupons for the two-year surveillance program were removed from the Unit 2 and Unit 3 spent fuel pools and analyzed in 2015. Inspection of the coupons included visual examination for surface anomalies, imperfections, blistering or pitting; length, width, and thickness measurements; neutron-attenuation testing for boron-10 content; and weight and specific gravity measurements. Results from each post-irradiated coupon surveillance were compared to the original pre-irradiated data for evidence of blistering, swelling (bulging), loss of material, and decrease in boron-10 areal density to determine if there has been any loss of neutron-absorption capability, and it was confirmed that no significant deterioration or degradation had occurred. This example provides objective evidence that the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program effectively monitors the parameters that are indicators of the ability of the Boralcan™ material to perform its intended function. The existing program contains acceptance criteria that will identify adverse trends in the ability of the material to absorb neutrons prior to a loss of intended function to ensure the assumptions in the spent fuel pool criticality analysis remain valid.

The operating experience relative to the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing Monitoring of Neutron-Absorbing Materials Other Than Boraflex program provides reasonable assurance that the reduction of neutron absorbing capacity, change in dimensions, and loss of material aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.28 Buried and Underground Piping and Tanks

Program Description

The Buried and Underground Piping and Tanks aging management program is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks including loss of material and cracking. It addresses piping and tanks composed of carbon steel, ductile iron, gray cast iron, and stainless steel exposed to soil, concrete, and underground environments. There are no buried or underground piping or tanks constructed of polymeric or cementitious materials within the scope of license renewal at PBAPS.

The program manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection), relies on inspection activities, including visual examination of coated buried and underground piping and tanks, electrochemical verification of the effectiveness of the cathodic protection system, nondestructive evaluation of pipe or tank wall thicknesses, and performance monitoring of fire mains. The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. The program uses the -850mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured. The program allows for soil corrosion probes to be used to demonstrate cathodic protection effectiveness during the annual surveys.

Inspections are conducted by qualified individuals. Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is projected to the end of the second period of extended operation, an increase in the sample size will be conducted. Degraded conditions such as loss of material, damaged coatings, non-conforming backfill, or improper cathodic protection system voltage are evaluated under the corrective action program. If a reduction in the number of inspections recommended in NUREG-2191, AMP XI.M41, Table XI.M41-2 is claimed based on a lack of soil corrosivity, as determined by soil testing, then soil testing is conducted once in each 10-year period, starting 10 years prior to the second period of extended operation.

Aging management of the buried Fire Protection System piping will be accomplished through monitoring the activity of the jockey pump.

This program does not address loss of material due to selective leaching. The Selective Leaching (B.2.1.22) program is used to manage loss of material due to selective leaching of susceptible materials.

The Buried and Underground Piping and Tanks aging management program will be enhanced as described below to provide reasonable assurance that buried and underground piping and tanks and components, constructed of steel and stainless steel will perform their intended function during the second period of extended operation.

NUREG-2191 Consistency

The Buried and Underground Piping and Tanks aging management program will be consistent with the ten elements of aging management program XI.M41, "Buried and Underground Piping and Tanks" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

1. Manage cracking for buried stainless steel piping, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed exposing the base material. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Acceptance Criteria (Element 6)**

2. Perform direct visual inspection of buried piping within the scope of license renewal in accordance with NUREG-2191, Table XI.M41-2, and sections 4.a and 4.b, during each 10-year period, beginning 10 years prior to the second period of extended operation. The number of inspections of buried piping will be based upon the as-found results of cathodic protection system availability and effectiveness. The length of piping for each inspection will be based on the recommendations in section 4.c. **Program Element Affected: Detection of Aging Effects (Element 4)**

3. Perform extent of condition inspections as follows: When measured pipe wall thickness, projected to the end of the second period of extended operation, does not meet the minimum pipe wall thickness requirements due to external environments, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-up inspections will be determined based on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-

year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval. **Program Elements Affected: Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)**

4. Upgrade existing cathodic protection system no later than 5 years prior to the second period of extended operation in accordance with NACE SP0169-2007 to ensure effective control of external corrosion of underground piping and tanks. **Program Elements Affected: Preventive Actions (Element 2) and Monitoring and Trending (Element 5)**

5. Perform examination of buried emergency diesel generator fuel oil tanks from the internal surface of the tank using volumetric techniques during each 10-year period, beginning 10 years prior to the second period of extended operation. A minimum of 25 percent coverage is required. **Program Element Affected: Detection of Aging Effects (Element 4)**

6. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping. **Program Element Affected: Preventive Actions (Element 2)**

7. Apply coating to buried portions of the 10-inch diameter stainless steel line from the torus dewatering tank to the condensate transfer pump suction line in accordance with approved station specifications, during the 10-year period prior to the second period of extended operation. **Program Element Affected: Preventive Actions (Element 2)**

Operating Experience

The following examples of operating experience provide objective evidence that the Buried and Underground Piping and Tanks program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the existing aging management program for buried and underground piping and tanks in support of preparing the license renewal application for second license renewal. The existing program includes activities from the following first license renewal aging management programs; Outdoor, Buried and Submerged Component Inspection Activities as described in UFSAR Section Q.2.5, and Emergency Diesel Generator Inspection Activities as described in UFSAR Section Q.2.4. The purpose of the review was to verify the intent of the existing activities, which is to monitor for loss of material and cracking of in scope underground piping, piping components, and tanks, is being effectively implemented in the first period of extended operation.

The aging management program effectiveness review included a review of maintenance history for documented completion of inspections from 2006 through 2016, and a review of operating experience within the corrective action program for identified age-related degradation of in scope piping from 2001 through 2016. The inspections performed per the Outdoor, Buried and

Submerged Component Inspection Activities aging management program have identified instances of corrosion of external surfaces of buried piping, degradation of external coatings, and the lack of effectiveness of the station's cathodic protection system. These issues have been identified during direct visual and volumetric inspections of buried piping systems and periodic monitoring and testing of the cathodic protection system. The results of these inspections were evaluated under the corrective action program and provided the appropriate information to direct repair/replacement of piping and coatings, implement upgrades to the cathodic protection system, and provide trendable, repeatable data on piping conditions that inform integrity evaluations. The program is being enhanced as part of a station multi-year capital project to upgrade the existing cathodic protection system in accordance with applicable NACE standards to ensure effective control of external corrosion of underground piping and tanks. These inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of this aging management program. The inspection activities associated with the emergency diesel fuel oil storage tanks identified no age-related deficiencies related to the external surfaces of the tanks.

In 2013 (Unit 2) and 2014 (Unit 3), pre-PEO implementation of the Outdoor, Buried and Submerged Component Inspection Activities and Emergency Diesel Generator Inspection Activities programs were also assessed via NRC regional inspection using inspection procedure 71003, with no adverse findings identified relative to in scope buried or underground piping or tanks. The aging management program effectiveness review determined that the program is being implemented in accordance with UFSAR Section Q.2.5, Outdoor, Buried and Submerged Component Inspection Activities, and Section Q.2.4, Emergency Diesel Generator Inspection Activities.

This operating experience provides objective evidence that the current Outdoor, Buried and Submerged Component Inspection Activities and Emergency Diesel Generator Inspection Activities are being effectively implemented to manage aging effects of in scope buried and underground piping and tanks. Continued implementation of the Buried and Underground Piping and Tanks program will assure that components within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. The PBAPS commitments to comply with NEI 09-14, Nuclear Buried Piping Integrity Initiative, required excavations and assessments to develop reasonable assurance of the leakage/structural integrity of buried piping within the scope of license renewal. Assessments driven by this initiative included evaluation of external corrosion susceptibility based upon materials of construction, soil conditions, coatings effectiveness, and cathodic protection system health. These excavations provided for direct visual observation of the external coatings and surfaces of piping and allowed for the assessment of conditions. The direct inspections noted that significant external general corrosion was not occurring as a result of the effectiveness of the preventative actions of the coatings, backfill, and cathodic protection. However, localized corrosion is occurring as a result of localized coating failures, construction damage, mixed metal in trenches, soil adhering to the piping, and the inability

of the cathodic protection system to address the local effects. As-found conditions were evaluated within the corrective action program and repaired, replaced, or trended, as applicable.

In addition to the direct methods of inspection, indirect methods utilizing guided wave technology are performed. The guided wave inspections provide data designed to assess accessible and inaccessible buried pipes for wall loss, and detects both internal and external corrosion. In many instances, guided wave inspections have been performed coincident with site excavations. When excavations are performed, permanent guided wave collars are typically installed at selected locations to allow for readily available on-demand data. Guided wave inspection assessments are qualitative in nature and are utilized to supplement direct UT data to support corrosion rate inputs in determination of remaining component life. The corrective action program is used to assure that appropriate corrective actions are implemented to resolve any identified adverse indications.

As an example of one of these inspection commitments, NDE UT inspections were performed on buried piping at excavation site #6 on the 16 inch “A” emergency service water (ESW) system supply piping in 2011, resulting in wall thickness readings that were approaching the minimum allowable wall thickness. Based upon projected wear rates at that location, the condition was entered into the corrective action program with a recommendation to repair. Prior to backfilling the excavation, this ESW piping was drained and repaired to restore wall thickness.

This example provides objective evidence that a comprehensive buried piping inspection program, that performs indirect and direct inspections focusing on high risk buried piping, has been implemented. Upon discovery of adverse indications, the program appropriate corrective actions are implemented. This example demonstrates that the inspection techniques implemented in this program are capable of detecting age-related degradation prior to a loss of the component intended function. This example also provides evidence that industry OPEX (NEI 09-14) is incorporated into the aging management program.

3. During three buried pipe excavations performed in 2011, an ANSI/ASME N45.2.6 and NACE qualified inspector performed coating inspections and completed an evaluation report on the coatings of the excavated buried pipes. The scope of work for these inspections and coating assessments of the exterior of the exposed buried pipe included:

- Visual inspection of coating condition to identify and characterize apparent coating defects
- Visual inspection of exposed substrate (if any) to access corrosion conditions
- Dry film thickness (DFT) measurements of protection (coatings, tape, etc.)
- Assessments of coating adhesion of intact coating
- Photographic documentation of representative conditions

- Written report with digital photographs provided in both paper and electronic formats

The excavation evaluation report assessed the buried pipes for all three buried pipe excavations. Excavation at site #6 exposed two carbon steel emergency service water pipes, two high pressure service water pipes, a standby gas treatment pipe, and a fire system pipe within the scope of license renewal. An approximately 10-foot length of each pipe was exposed in the 10-foot x 10-foot stepped excavation. The excavation evaluation report cited that pipes had a factory-applied Somastic coating with Bitumastic tape wrap on joints, fittings, and other field-applied locations. The coatings were generally in good condition with no visible damage or coating failure and were tightly adhered to the substrate with good overlap with tight edges and were still pliable.

Inspection of the 18 inch Unit 2 high pressure service water pipe revealed that damage had been experienced to the tape wrap coatings. The tape wrap coating degradation was largely isolated to field wrapped elbows and fittings. Soil and water intrusion was evident in the areas of damaged wrap. The shop applied Somastic coatings were generally in good condition. External corrosion was noted in the areas of damaged tape wrap. Localized corrosion readings were taken and determined to be acceptable. The coatings were replaced with Tapecoat coatings to provide barrier protection of the damaged areas. The report concluded that the coating was intact and generally performing well. Localized coating damage was a result of mechanical damage resulting from original installation or excavation.

This example provides objective evidence that the aging management program to detect and evaluate potential degradation to buried piping and components prior to loss of intended function is effective.

4. In 2016, cathodic protection performance evaluations revealed that only about five percent of anodes met acceptance criteria based upon area potential earth current (APEC) surveys. The lack of cathodic protection effectiveness has resulted in increased corrosion to buried and underground piping.

A multi-year capital project has been initiated to rehabilitate the cathodic protection system site-wide in an effort to reduce external corrosion based on buried piping program margins. The project has implemented improvements to the cathodic protection system which included installing underground monitoring stations to aid in the proper design of the cathodic protection system. These inputs are being utilized to size/design upgraded cathodic protection rectifiers and install sacrificial anodes to enhance overall cathodic protection system performance and effectiveness. In addition, internal corrosion issues for raw water piping are being resolved by a multi-year capital project plan and are included in the Open-Cycle Cooling Water System (B.2.1.11) program. The project plans to address known buried pipe program equipment vulnerabilities and safeguard remaining margin for all buried commodities on site.

This example provides objective evidence that although the current state of the cathodic protection system is degraded, measures to maintain and enhance the cathodic protection system are being implemented to ensure adequate preventive measures are in place to protect buried piping during the second period of extended operation.

The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Buried and Underground Piping and Tanks program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Buried and Underground Piping and Tanks program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Buried and Underground Piping and Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.29 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program is a new condition monitoring program that includes visual inspections of internal coatings/linings of cast iron, ductile iron, and carbon steel piping, piping components, valve bodies, tanks, heat exchangers, accumulators, and blower housings exposed to raw water, treated water, waste water, condensation, and lubricating oil. There are no piping or components with internal coatings/linings in the program scope that are exposed to closed-cycle cooling water, treated borated water, or fuel oil. This program is not used to manage the integrity of coatings applied to external surfaces of piping or components.

The internal surfaces of the Condensate Storage Tanks and Refueling Water Storage Tanks are coated; aging management for these tanks is covered under the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.18) program and includes the applicable requirements for coating inspections from the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. Aging management of galvanized piping in the Plant Equipment and Floor Drain System, and internally coated tanks in the Radwaste and Reactor Water Cleanup (RWCU) Systems will be performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program.

The program complies with NRC Regulatory Guide (RG) 1.54 and the ASTM standards endorsed by the RG. Guidance contained in other industry documents, such as EPRI Report 1019157 and ACI Standard 201.1R, is also considered.

The scope of the program will include internal coatings/linings for in scope piping, piping components, heat exchangers, and tanks in the following systems:

- Auxiliary Steam
- Emergency Service Water
- Fire Protection
- High Pressure Coolant Injection
- High Pressure Service Water
- Standby Liquid Control

For these components, loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component’s, or downstream component’s, current licensing basis intended functions identified under Title 10 of the Code of Federal Regulations (10 CFR) 54.4(a)(1), (a)(2), or (a)(3). This includes components that are relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with regulations for fire protection (10CFR50.48), environmental qualification

(10CFR50.49), anticipated transient without scram (10CFR50.62), and station blackout (10CFR50.63).

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will include periodic visual inspections to verify the integrity of internal coatings designed to adhere to and protect the base metal. For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. Inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide (RG) 1.54. However, inspection intervals should not exceed those specified in NUREG-2191, AMP XI.M42, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

Inspectors are trained and qualified in accordance with ANSI N45.2.6. The station coatings engineer will be trained and qualified in accordance with ASTM D7108-05. For cementitious coatings/linings, inspectors should have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience. Inspection results that do not satisfy established acceptance criteria are entered into the Peach Bottom 10 CFR 50, Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected.

The program will be implemented through various station procedures and work activities. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist, and should be limited to a few intact small blisters that are completely surrounded by sound material, and with size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompass sound coating/lining material. These inspections, and subsequent repairs, replacements, or evaluations of internal coatings will provide reasonable assurance that in scope components and downstream components will meet current licensing basis intended functions for the period of extended operation.

This new program will be implemented prior to the second period of extended operation.

NUREG-2191 Consistency

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program will be consistent with the ten elements of aging management program XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks" specified in NUREG-2191 with the following exceptions:

Exceptions to NUREG-2191

1. NUREG-2191 states that periodic inspections of a sample of piping internally lined with concrete are performed to verify degradation has not occurred, leading to loss of material or downstream effects such as reduction in flow and pressure. Opportunistic inspections of concrete lined fire system main loop piping will be performed. **Program Element Affected: Detection of Aging Effects (Element 4)**

Justification for Exception:

Concrete lined ductile iron and gray cast iron fire system main loop piping is buried. Inspection of this piping is highly intrusive and would require excavation and implementation of a complex temporary modification to maintain a functional fire water header. Management of the effects of aging for the fire water system is described AMP XI.M27, “Fire Water System.” In accordance with the Fire Water System aging management program, the following tests and inspections will be performed:

- Fire water system underground loop and main header flow test is conducted at least once per three years. The flow test procedure is designed to establish various expected flow conditions in the fire system underground loop and plant main supply headers, such that the main fire system headers are flushed and cleared of corrosion products and sediment. Water is circulated through the fire mains and discharged back to the Susquehanna River, permanently removing corrosion products and sediment. During the flow test, system hydraulic characteristics are measured and evaluated for indication of internal piping degradation or flow obstructions. The flow test measures system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion, sediment buildup or fouling will be detected in a timely manner.

- Underground supply piping is flushed through each of the outdoor fire hydrants annually and flow tests are performed for each hose station every three years.

- Wet pipe sprinkler main drain flow tests and inspector test flushes are performed at least every two years to assure adequate water supply and proper system performance. A 2-inch main drain test is performed for wet pipe sprinkler systems with alarm control valves to monitor and trend system pressure during flow conditions and identify degraded water supply conditions should they occur.

- The motor and diesel driven fire pumps are flow tested once every 18 months to assure flow and pressure requirements are met.

Together, these tests provide reasonable assurance that flow blockage would be detected just as effectively as if internal inspections were being periodically conducted on a portion of the piping in accordance with NUREG-2191, AMP XI.M42, Table XI.M42-1. In addition, the fire water system is maintained at required operating pressure. Alarm circuits monitor the system pressure, and low pressure is annunciated in the main control room via the motor driven and diesel driven fire pump start logic. A loss or decrease in system pressure would be noted and corrective actions initiated. This continuous monitoring is an effective means to detect potential through-wall flaws in the piping and piping components.

In 2014, during a modification to the fire water system, a portion of the concrete lined fire main loop piping was opportunistically inspected. After approximately 40 years of service, visual examination found the concrete liner to be in good condition. The concrete was tightly adhered to the pipe inner surface with no evidence of degradation. This operating experience, detailed in operating experience example 2 below, provides additional assurance that the fire water main loop piping concrete liner will not lose its integrity, and prevent the piping or downstream components from performing their intended functions.

The NRC approved a GALL exception based on very similar justification as documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2, Docket No. 50-341, July 2016 (ADAMS Accession Number ML16190A241)

2. NUREG 2191 recommends that coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. The High Pressure Coolant Injection System lube oil reservoir internal coating will not be repaired or replaced. **Program Element Affected: Corrective Actions (Element 7)**

Justification for Exception:

Lessons learned and improved maintenance practices for the HPCI System Terry Turbines (OEM) have been communicated at industry meetings facilitated by NMAC's Terry Turbine Users Group and are incorporated in the High Pressure Coolant Injection (HPCI) Maintenance Guide. This guide is the basis for the station’s HPCI turbine maintenance procedure. Section 20.2.5, “Inspection and Maintenance,” of EPRI TR-1007459, “Terry Turbine Maintenance Guide, HPCI Application,” dated November 2002, states the following: “Remove any damaged preservative paint coating. Do not attempt to repaint the surfaces of the oil reservoir.” Defective, damaged, or degraded preservation paint coating on the HPCI turbine lube oil reservoir will be removed, but will not be repaired or replaced. Removal of the paint coating will ensure flow blockage will not occur. Periodic inspections of the HPCI lube oil reservoirs will continue to be performed per Terry Turbine Users Group recommendations.

The NRC approved a GALL exception based on very similar justification as documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2, Docket No. 50-341, July 2016 (ADAMS Accession Number ML16190A241).

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management effectiveness review was performed of the existing aging management activities to periodically inspect the HPCI turbine lube oil reservoir coating in support of preparing the license renewal application for second license renewal. These activities are implemented within the HPCI and RCIC Turbine Inspection Activities aging management program as described in UFSAR Section Q.2.10. The purpose of the aging management program effectiveness review was to verify the intent and effectiveness of the existing activities that assure degradation of the coating in the HPCI lube oil reservoirs does not affect the intended functions of the HPCI System. These inspections are required to be performed once every four years (i.e., during every other refueling outage).

The effectiveness review evaluated the adequacy of the implementing documents, inspection documentation, the frequency of performance as compared to the commitment, and implementation of corrective actions when required. Inspection activities performed from 2005 to 2016 were reviewed. A total of 11 HPCI lube oil reservoir inspections were reviewed, six for Unit 2, and five for Unit 3. The review also utilized the data from a review of the implementation of the HPCI and RCIC Turbine Inspection Activities aging management program performed in 2012.

The review identified the following:

- Inspections are implemented via HPCI minor and major inspection preventative maintenance work orders and maintenance procedures. The work orders and procedures contain adequate guidance to implement the first license renewal commitment. A corrective action program issue report was generated in 2012 that enhanced the implementing maintenance procedure to ensure an issue report is generated when lube oil reservoir coating degradation is identified.

- Inspection procedure steps were signed as complete, and work orders were annotated with completion remarks documenting completion of the coating inspections.

- The inspections were performed more frequently than required. The average time between inspection was approximately every two years as compared to the required inspection frequency of four years. This was the result of performance of minor and major HPCI inspections, both of which include draining and inspection of the lube oil reservoir and coating.

- Two corrective action program issue reports were identified. In addition to the report above, an issue report was generated in 2012 to document degradation of the preservation coating in the Unit 2 reservoir during the refueling outage. The degradation was located near the top of the reservoir and not in the oil flow path. Corrective actions included filter inspection, oil sampling for debris, reservoir cleaning, and engineering evaluation of the condition. Engineering evaluated the corrective actions as adequate, and the system was returned to service. Subsequent inspections in 2014 and 2016 have documented the coating in a similar condition, with no impact on downstream components or overall HPCI System operation.

This review provides objective evidence that HPCI lube oil reservoir coating inspections are being performed in accordance with the HPCI and RCIC Turbine Inspection Activities aging management program as described in UFSAR Section Q.2.10. The periodic inspections and resulting corrective actions are effective in ensuring that the condition of the coating in the HPCI lube oil reservoir will not affect the HPCI System turbine lube oil components ability to perform their intended functions.

2. In June 2014, as part of a fire valve replacement project, point indications on the internal concrete lining of main fire piping were identified. The condition was entered into the corrective action program. To further assess the condition of the concrete lining, a section of the piping was removed and sent to Exelon Power Labs for evaluation. The piping was sectioned into two pieces to investigate the condition of the concrete lining. Visual examination found the lining to be in good condition. The concrete was tightly adhered to the pipe inner surface with no evidence of degradation. The concrete was then removed from the piping to perform metallurgical evaluation of the base metal. The piping inner surface was found to be in excellent condition. Dimensionally, the piping was found to be in the expected thickness range, and hardness was consistent with that expected for grey cast iron material. The concrete was uniform in thickness. Chemical analysis of the concrete was performed. Alkalinity and pH were found to be typical for concrete material.

This example provides objective evidence that opportunistic inspections of piping components and their internal coatings are performed. In addition, this example demonstrates that the corrective action program is used effectively to evaluate potential degradation of piping components and their internal coatings.

3. In June 2012, an inspection of the internal coating of the domestic water accumulator tank was performed. Some indications of deterioration of the tank lining were identified by maintenance personnel. The PBAPS coatings engineer was contacted to evaluate the condition of the lining. The evaluation concluded that the tank lining was acceptable for the near future, but should be replaced. The issue was entered into the corrective action program for management approval and funding. The tank is scheduled to be replaced with a stainless steel tank in 2018.

This example provides objective evidence that internal coating inspections of tanks are being performed, and trained and qualified coatings engineers are evaluating conditions for continued operation. This also demonstrates that the corrective action program is used effectively to address plant material condition issues.

4. In November 2014, the Unit 2 condensate storage tank (CST) was drained and an inspection of the internal coatings was performed by a qualified coatings inspector. Approximately 65 percent of the protective coating system was found to be covered with intact blisters. Blister sizes and frequency are measured in accordance with ASTM D 714-09, “Standard Test Method for Evaluating Degree of Blistering of Paint.” Sizes are measured as follows: No. 8, 6, 4 and 2; No. 8 is the smallest blister size and No. 2 is the largest blister size. Frequency is measured as few, medium, medium dense, and dense. Blister frequency on the floor is few to medium dense. Blister frequency on the tank wall was few to dense. Blisters are typical in size and frequency from plate to plate on the tank wall. The majority of blisters are small (No. 8). Blisters on the tank floor are smaller and less frequent than on the tank wall. Coating blisters that generally occur in immersion areas are osmotic blisters caused by entrapped solvents or other entrapped contaminants. Solvent entrapment is caused by insufficient ventilation during application and curing of the protective coating. Several blisters were tested by hand to determine if the caps were soft or cracked. Tested blisters were intact, hard, and were not cracked when viewed with the unaided eye. Osmotic blistering due to solvent entrapment is considered a common failure mode for solvent based coatings in immersion service environments. The evaluation of the coating condition concluded it was acceptable to return the CST to service with a follow-up inspection required within five years.

In October of 2016, the Unit 2 CST was drained and an inspection of the internal coatings and tank bottom measurements were performed. The internal coatings were re-inspected and determined to be similar in condition to the conditions observed in 2014. The bottom was scanned searching for locations less than the minimum allowable thickness. There were no locations that were identified below the minimum allowable thickness, but there were three locations that were marginally above this value. An evaluation was performed to determine the projected remaining life of the tank bottom at these identified locations. Subsequent inspection and repair activities have been scheduled based upon the corrosion rate margins determined in the evaluation. An action request was entered into the corrective action program to perform a recoat of the internal coating of the Unit 2 CST, scheduled to be completed in 2020.

This example provides objective evidence that internal coating inspections of tank are being performed, and trained and qualified coatings engineers are evaluating conditions for continued operation using industry standard practices. This also demonstrates that the corrective action program is used effectively to address plant material condition issues.

The operating experience relative to the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program did not identify an adverse trend in performance. The inspection methods used for inspections of internally coated/lined piping and tanks have been proven effective in detecting aging effects including loss of coating or lining integrity and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.30 ASME Section XI, Subsection IWE

Program Description

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of 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.

The program includes preventive actions that provide reasonable assurance that moisture levels associated with an accelerated corrosion rate do not exist in the exterior portion of the BWR Mark I steel containment drywell shell. The actions consist of ensuring that the air gap drains are clear. Additionally, the top of the sand pocket region was sealed during original construction to exclude water from the sand pocket area.

The program is also supplemented to include preventive actions to provide reasonable assurance that bolting integrity is maintained. The preventive actions 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 structural bolting.

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 surface examination to detect cracking for high temperature mechanical penetrations subject to cyclic loading but 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. Inspection results are compared with prior recorded results in acceptance of components for continued service.

The program includes aging management of steel and stainless steel surfaces and components such as the drywell shell and integral attachments, torus shaped pressure suppression chamber, suppression chamber integral attachments, containment penetrations including flued heads and bellows, containment hatches and airlocks, downcomers and bracing, moisture barriers, and pressure-retaining bolting for cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing in air–indoor uncontrolled and treated water environments.

The current program complies with ASME Section XI, Subsection IWE, 2001 Edition through the 2003 Addenda, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified

12 months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the second period of extended operation.

PBAPS primary containments are BWR Mark I metal containments. High strength containment closure bolting susceptible to cracking is not used; therefore, surface examination to detect cracking is not applicable. Environments include air-indoor uncontrolled and treated water. The scope of the ASME Section XI, Subsection IWE program is consistent with the scope identified in Subsection IWE-1000 and includes the Class MC pressure-retaining components and their integral attachments including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal.

The program utilizes inspections that detect degradation before loss of intended function. The ASME Code Section XI, Subsection IWE program relies on design change procedures. The program implements the requirements of IWE by providing visual examinations (General Visual and VT 3) and augmented inspections (VT-1) for evidence of aging effects that could affect structural integrity or leak tightness of the primary containment. Areas subject to augmented inspection are subject to visual inspection (VT-1) and volumetric (ultrasonic) examination techniques as required by engineering per IWE-1240. The program addresses the E-A and E-C examination categories described in Table IWE-2500-1 and as approved per 10 CFR 50.55a. The program specifies examinations of accessible surfaces to detect aging effects as addressed in IWE-3500. The frequency and scope of examinations specified is in accordance with 10 CFR 50.55a, and ASME Section XI, Subsection IWE 2400.

The program complies with ASME Section, XI Subsection IWE for inspection of Class MC and metallic shell pressure-retaining components and their integral attachments, in accordance with the provisions of 10 CFR 50.55a. The monitoring methods have been demonstrated effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant aging.

The program provides for periodic inspections for the presence of age-related degradation on all accessible surfaces of the containment on a scheduled basis. When examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period, in accordance with Examination Category E-C.

The acceptance criteria for the ASME Section XI, Subsection IWE program are in accordance with the requirements of the ASME Code, Subsections IWE-3000 and IWE-3500.

Indications are evaluated and compared to acceptance standards. Unacceptable conditions are recorded and documented in accordance with the corrective action program and supplemental examinations are performed in accordance with IWE-3200. Conditions which do not meet the acceptance criteria are accepted by an engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

Repairs and re-examinations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE 3500. Component reexaminations are conducted in accordance with the requirements of IWA-2200 and the results are recorded to demonstrate that the repair meets the owner defined acceptance standards per IWE-3500.

NUREG-2191 Consistency

The ASME Section XI, Subsection IWE aging management program will be consistent with the ten elements of aging management program XI.S1, "ASME Section XI, Subsection IWE" specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191 states that steel, stainless steel, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis, are monitored for cracking and are supplemented with surface examination (or other applicable technique) in addition to visual examination to detect cracking. Peach Bottom does not monitor for cracking utilizing supplemental surface examinations except at high temperature mechanical penetrations. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

Justification for Exception

The PBAPS drywell contains stainless steel penetration sleeves, dissimilar metal welds, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. The Peach Bottom primary containment was designed in accordance with ASME Section III, 1965 edition and applicable addenda through the Summer 1966 edition. No fatigue analysis or exemption/waiver was required per this code year or original construction specifications as permitted by later code year editions. PBAPS has performed an assessment that has shown that had the drywell been designed to ASME Section III, 1974 edition, it would have met the criteria in subsection NE-3222.4(d) ‘Vessel not requiring analysis for cyclic operation’. The criteria that were met to address this condition included: 1) atmospheric to operating pressure cycle, 2) normal operation pressure fluctuation, 3) temperature difference – startup and shutdown, 4) temperature difference – normal operation, 5) temperature difference – dissimilar metals, and 6) mechanical loads. This drywell fatigue waiver assessment concluded that the components that could be subject to cyclic loading, but have no current licensing basis fatigue analysis, are subjected to an acceptable and negligible amount of fatigue, and therefore no visual or surface examinations will be performed. The assessment did not include drywell penetration bellows which have fatigue analysis and penetration adapters of high temperature drywell mechanical penetrations.

The majority of the surface of these components are not accessible for visual inspection or surface examination for cracking due to the Mark I containment design. The program will be enhanced to perform surface examinations on accessible portions of drywell high temperature mechanical penetrations in addition to visual examinations to detect cracking for penetrations that could be subject to cyclic loading but have no CLB fatigue analysis. Original design and installation specifications for containment penetration components such as bellows, welds, and penetration adapters required initial surface examinations to ensure no flaws existed as part of initial installation. Appropriate integrated and local leak rate testing is conducted for pressure boundary components per the 10 CFR 50 Appendix J aging management program. Through-wall cracking would be detected by the type A integrated leak rate test. Additionally, VT-3 examinations are performed on accessible portions of the containment penetrations in accordance with the IWE program. Peach Bottom has not experienced a failure of the above listed containment components and integrated leak rate test results have shown significant margin. Industry operating experience has also shown strong performance of the subject primary containment components. License renewal applications for other similar Mark I containments designed to later code years have credited fatigue waivers. The design of penetrations where fatigue waivers are not credited limit loads from the piping onto the drywell by either using bellows or installation of small bore diameter pipe. Therefore, the existing 10 CFR Part 50 Appendix J leak testing and ASME Section XI, Subsection IWE, are adequate to detect cracking without requiring surface examination of these containment components subjected to low levels of fatigue.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program elements:

1. Perform surface examinations on accessible portions of high temperature drywell mechanical penetrations, in addition to visual examinations, to detect cracking, once per 10-year interval during the second period of extended operation. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWE program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the primary containment inservice inspection (CISI) portion of the Inservice Inspection (ISI) Program activities described in UFSAR Section Q.1.9, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage age-related degradation of the steel and stainless steel primary

containment structures and components, is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of inspection records and remaining inspection schedules during the second 10-year CISI Inspection Interval (November 2008 through November 2018). The review also included pertinent issues found in the corrective action program from 2001 to 2016, searching for age-related degradation of components within the scope of the ASME Section XI, Subsection IWE aging management program.

The review identified that inspections of components within the scope of the CISI portion of the ISI Program are being performed in accordance with the extent and schedule described in ASME Section XI, Subsection IWE-2500 and the PBAPS fourth 10-year ISI Program Plan. The review identified that inspections performed within the program are effective at identifying age-related degradation of in scope components before significant degradation has occurred. Age-related issues were evaluated in accordance with ASME Code Section XI requirements and corrective actions were taken to prevent further degradation in effective implementation of this aging management program. The review concludes that the components within the scope of the primary containment Inservice Inspection portion of the ISI Program are in good condition.

This operating experience provides objective evidence that the current CISI program is being effectively implemented to manage aging effects. Continued implementation of the ASME Section XI, Subsection IWE aging management program will assure that the components within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. In 2015, during Unit 3 CISI inspections of the primary containment, the examiner noted damaged and missing areas of the moisture barrier at the containment shell to drywell floor interface. There was no corrosion or damage to the containment shell noted. Per ASME Section XI, Subsection IWE-3510.4, moisture barriers with wear, damage, erosion, tear, surface cracks, or other defects that permit intrusion of moisture against inaccessible areas of the pressure-retaining surfaces of the metal containment shell shall be corrected. The above noted anomalies were entered into the corrective action program. An engineering evaluation was performed and confirmed that the condition of the moisture barrier required repair prior to unit startup from the refueling outage to prevent moisture infiltration against the containment vessel. The appropriate repairs to the moisture barrier were performed prior to unit startup.

This example provides objective evidence that the CISI program examinations performed by qualified personnel are capable of detecting damage to in scope components and other indications of possible age-related degradation, and that the moisture barrier degradation was repaired prior to the onset of corrosion to the containment shell. This example also demonstrates that deficiencies are entered into the corrective action program and actions are taken to address deficiencies accordance with ASME Code Section XI requirements.

3. In 2014, during Unit 2 CISI inspections of the underwater portions of the

torus, the diver inspector identified a local area (1/8 inch diameter) of general corrosion with 0.126 inch of metal loss of the nominal 0.675 inch thick plate on the inside with no losses identified on the outside. The condition was entered into the corrective action program and was evaluated prior to the unit startup from the refueling outage. An engineering evaluation was performed and confirmed acceptability of the torus shell pressure boundary with the as-found local general corrosion without repair. The associated coatings were required to be repaired prior to startup. Follow-up inspections will be performed under the PBAPS CISI program in accordance with table IWE-2500-1, Examination Category E-C.

This example provides objective evidence that the CISI program examinations are capable of detecting damage to in scope components and other indications of possible age-related degradation, deficiencies are entered into the corrective action program, that actions are taken to evaluate and address deficiencies accordance with ASME Code Section XI requirements, and follow-up inspections are performed.

4. NRC Information Notice 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. Bellows on the vent lines between the drywell and the torus and bellows on various drywell pipe penetrations are the two categories of primary containment bellows at PBAPS.

The bellows listed in UFSAR Table 5.2.2, "Containment Penetrations Compliance with 10 CFR 50, Appendix J," are local leak rate testable bellows and are local leak rate tested in accordance with 10 CFR 50, Appendix J, Option B, Type B testing. Local leak rate test procedures for containment expansion bellows include verification of flow through the annulus between plies of the bellows, which ensures that restrictions between the plies that could conceal a leakage path do not exist. A review of leakage test records since June 1977 has revealed no failures of these bellows.

This example provides objective evidence that industry operating experience is being reviewed and evaluated to confirm that station testing procedures are effective to maintain containment integrity.

5. NRC Information Notice 2006-01 was issued to alert licensees that a through-wall crack was discovered in a torus shell at another BWR. The issue was reviewed for applicability to PBAPS, and the results documented in the corrective action program. At the BWR where the cracking was found, the High Pressure Coolant Injection (HPCI) System turbine exhaust line that discharges into the suppression pool is open ended and does not have an end cap or sparger to diffuse energy. The PBAPS HPCI system design employs the use of a sparger at the discharge of the turbine exhaust line which reduces the loads on the torus shell. VT-2 and VT-3 inspections were performed on the

nozzle and the torus shell next to the HPCI System and Reactor Core Isolation Cooling System exhaust penetrations and the support legs to the torus shell with satisfactory results. No further actions were required.

This example provides objective evidence that industry operating experience is being reviewed, evaluated, and actions are taken to assure that events that have occurred at other plants will not occur at PBAPS.

6. Generic Letter 87-05 described drywell shell degradation, which 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, and subsequent wetting of the drywell shell in the sand pocket area where the water flowed into the open sand pocket at the bottom of the air gap. During refueling activities, a potential leakage path could exist through the drywell bellows region, as experienced on the Mark I containment. The drywell bellows provides a flexible seal between the drywell and the reactor cavity. The drywell to concrete seal drains are also located in this bellows area. Leakage of these components could allow water to enter the air gap region.

The PBAPS reactor cavity seal drain line design incorporates full penetration welds, instead of bolted connections. Additionally, the PBAPS design incorporates a weir wall that prevents drywell bellows leakage from entering the drywell air gap before being drained away by the seal rupture drains. Unlike the Mark I containment described in Generic Letter 87-05, the PBAPS design also prevents in-leakage to the sand pocket by use of a sheet metal cover over the sand pocket which is sealed to the outside of the drywell shell. This sealed cover separates the sand pocket from the air gap region. Located above the sealed cover plate are drywell air gap drains that drain any in-leakage away from the sealed cover plate area. This design provides substantial defense against water entering the sand pocket region. With no water intrusion, potential degradation on the outside surface of the drywell at the sand pocket area is prevented.

As part of the PBAPS CISI program, several periodic examinations and tests of components associated with the drywell air gap region confirm that abnormal conditions that could lead to containment degradation do not exist. The four drywell air gap drain lines are functionally tested (i.e. smoke test) to verify that the drywell air gap drain lines are unclogged and functional. Visual examinations are also performed on the drywell air gap drain lines when the refueling cavity is flooded to look for signs of leakage. These examination results did not reveal signs of leakage into the air gap when the reactor cavity has been flooded.

When stabilizer access hatches are opened to perform the Examination Category E-A examinations on the weld to the shear lugs attached to the exterior of the drywell shell, periodic VT-3 visual examinations are performed on the drywell exterior stabilizer support, the accessible exterior surface of the drywell to look for evidence of degradation or leakage, and the accessible drywell air gap to look for items that could trap water in the unlikely event of leakage through the refueling bellows. There has been no reported evidence of moisture or degradation when the stabilizer hatch covers at the top of the drywell cylinder are opened to perform examinations of the shear lugs attached to the exterior of the drywell shell.

This example provides objective evidence that conditions do not exist at the sand pocket area that would result in corrosion. The current CISI program is being effectively implemented to manage aging effects. Continued implementation of the ASME Section XI, Subsection IWE aging management program will assure that the potential for corrosion in the sand pocket area of the drywell shell is managed during the second period of extended operation.

The operating experience relative to the program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI, Subsection IWE program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the ASME Section XI, Subsection IWE program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced ASME Section XI, Subsection IWE program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.31 ASME Section XI, Subsection IWF

Program Description

The ASME Section XI, Subsection IWF aging management program is an existing condition monitoring program that consists of periodic visual examination of ASME Section XI Class 1, 2, 3, and MC piping and component support members for loss of material, loss of mechanical function, cracking, and loss of preload in air-indoor uncontrolled, air-outdoor, raw water, and treated water environments. Bolting for supports is also included with these components and inspected for loss of material and loss of preload by inspecting for missing, detached, or loosened bolts and nuts. The program utilizes procedures that are consistent with industry guidance to ensure proper specification of bolting material, lubricant, and installation torque to prevent or minimize loss of bolting preload or other loss of structural integrity. Indications of degradation are entered in the corrective action program for evaluation or correction to ensure the intended function of the component support is maintained.

This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. The enhanced program implements additional inspections beyond the inspections required by the 10 CFR 50.55a ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection is conducted within five years prior to entering the second period of extended operation. 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 will be performed to detect cracking in addition to the VT-3 examination.

Sixty ASTM A490 bolts, 2 ¼ inch diameter, are used for the attachment of the reactor vessel support skirt to the reactor pedestal. Four ASTM A490 threaded rods, 1 ¼ inch diameter, are used for lateral bracing for the core spray pumps. The program will be enhanced to perform VT-3 examination of all ASTM A490 bolting materials and to perform a volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a sample of these ASTM A490 bolting materials. Volumetric examinations will be qualified in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. These volumetric examinations will be performed once per 10-year interval during the second period of extended operation to detect cracking in addition to the VT-3 examination of all ASTM A490 bolting materials. The sample of ASTM A490 bolting materials subject to volumetric examination will consist of 20 percent of the reactor vessel skirt population and be comprised of 12 of the bolts used for each of the reactor vessel skirts, for a total of 24 ASTM A490 bolts.

The bases for the sample selection is that the bolts used at the reactor vessel support skirt are a larger diameter than the threaded rods used for the core spray pumps, the installation loads are much higher on the reactor vessel support skirt bolts than for the threaded rods that laterally restrain the core spray pumps, and the core spray pumps are not normally in operation.

The sample size using 20 percent is consistent with other sampling programs. A VT-3 examination will be performed of all the ASTM A490 bolting materials used for the reactor vessel support skirts and lateral bracing for the core spray pumps to ensure that the sample is representative of the bolts most susceptible to degradation. The implementing documents for performing the volumetric examinations will contain criteria for extending the ASTM A490 bolt examination scope to other ASTM A490 bolts used in similar joint configurations and environmental exposure conditions if the volumetric examination of an ASTM A490 bolt shows adverse results, which is similar to the methodology used by the ASME Code IWF-2430 for IWF component supports.

If a component support does not exceed the acceptance standards of IWF-3400 but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

The ASME Section XI, Subsection IWF program utilizes inspections that detect degradation before loss of intended function. Preventive measures associated with structural bolts are addressed in implementing procedures.

NUREG-2191 Consistency

The ASME Section XI, Subsection IWF aging management program will be consistent with the ten elements of aging management program XI.S3, "ASME Section XI, Subsection IWF" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the second period of extended operation. **Program Element Affected: Scope of Program (Element 1)**

2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. Conduct the one-time inspection within five years prior to entering the second period of extended operation. Select the additional supports from the remaining population of IWF piping supports. Ensure that the sample expansion includes components that are most susceptible to age-

related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment). **Program Element Affected: Detection of Aging Effects (Element 4)**

3. Perform VT-3 examinations of all ASTM A490 bolting materials, used for the reactor vessel support skirts and for the core spray pump supports once per 10-year interval during the second period of extended operation. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of 12 ASTM A490 bolts at each of the reactor vessel support skirts, once per 10-year interval during the second period of extended operation. **Program Element Affected: Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWF program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the aging management activities of the ASME Section XI, Subsection IWF program that are currently performed by the Inservice Inspection (ISI) Program as described in UFSAR Section Q.1.8, and the Primary Containment Inservice Inspection Program, as described in UFSAR Section Q.1.9, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, which is to manage age-related degradation of ASME Class 1, 2, 3, and MC piping and component supports, is being effectively implemented in the first period of extended operation.

The aging management program effectiveness review was comprised of a review of implementing documents, inspection records and remaining inspection schedules during the fourth 10-year ISI Inspection Interval (November 2008 through December 2018). The review also included pertinent issues found in the corrective action program from 2001 to 2016, searching for age-related degradation of components within the scope of the ASME Section XI, Subsection IWF aging management program. In addition, the review included a FASA in 2014, which verified the implementation of supplemental examinations and which validated that required inspections had been performed or scheduled appropriately in the interval, as well as the 2016 ISI program health report, which includes the IWF program, and recent reviews of applicable industry operating experience.

The review identified that inspections of piping and component supports within the scope of the ASME Section XI, Subsection IWF program are being performed in accordance with extent and schedule as described in ASME Section XI, Subsection IWF. The review identified that examinations performed within the program are effective at identifying age-related degradation of in scope ASME Section XI Class 1, 2, 3, and MC piping and component support members for loss of material, loss of mechanical function, cracking, and loss of preload. Age-related issues were evaluated in accordance with ASME Code Section XI requirements resulting in effective implementation of this aging management program.

Industry operating experience, such as degradation of threaded bolting and fasteners as identified in EPRI NP-5769, NRC IE Bulletin 82-02, and NRC Generic Letter 91-17, has been considered. PBAPS plant-specific operating experience has not identified stress corrosion cracking or fatigue failures of bolting including high strength bolting associated with Class 1, 2, 3 or MC supports. Bolts, welds, and other support components are visually examined for loss of integrity due to conditions including corrosion, signs of deformation, tightness of bolting and freedom from cracks or crack like conditions.

Another example of industry operating experience involves deviations in the supporting forces of mechanical constant supports as described in NRC IN 2009-04. Support examination procedures include requirements to verify load settings and excessive vibration of spring can supports and constant supports.

The review of the ISI program health report did not identify any deficiencies associated with the IWF program and the recent reviews of industry operating experience revealed that external industry operating experience was being used to identify whether there was any applicable information.

The aging management program effectiveness review determined that the program is being implemented in accordance with UFSAR Sections Q.1.8 and Q.1.9 in conjunction with the corrective action program, which is used to improve the IWF program.

This operating experience provides objective evidence that the existing ASME Section XI, Subsection IWF aging management program is being effectively implemented to manage ASME Section XI Class 1, 2, 3, and MC piping and component support members for loss of material, loss of mechanical function, cracking, and loss of preload. Continued implementation of the ASME Section XI, Subsections IWF aging management program will assure that the ASME Section XI Class 1, 2, 3, and MC piping and components support within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. Review of plant operating experience identified examples where degraded conditions were identified, the conditions documented in the corrective action program, the cause of the condition evaluated, corrective actions taken, inspections performed of additional supports to identify the extent of condition, and follow-up inspections performed to verify that the conditions were corrected. The example below describes a pipe penetrating the west wall of the Reactor Building lifting off supports inside the Reactor Building due to subsidence outside the building.

In 1997, small gaps were identified between the supports and emergency service water piping and high pressure service water piping, which penetrates the west wall of Reactor Building. The gaps were determined to be acceptable. The ISI program was augmented to add follow-up inspections of these supports, which were subsequently discontinued after satisfactory inspections. In 2007, small gaps were again identified between the supports and emergency service water piping and high pressure service water piping, which penetrates the west wall of Reactor Building. The gaps were typically about 1/16 inch or less. The supports were evaluated, some were determined to be acceptable with the gaps, and other supports were corrected to close the gaps by shimming or adjusting supports. Additional supports were inspected in 2008 to identify the extent of the condition. Additional small gaps between piping and supports were identified and entered into the corrective action program. Other areas were inspected along the routings for the buried emergency cooling water, emergency service water, and high pressure service water lines at the safety-related structures. Due to the site terrain, the west side of the Reactor Building was found to be the most prone to this condition.

Subsequently, in 2009, it was discovered that a cable ductbank west of the Reactor Building had experienced a shear displacement at the span over backfill, which was extending between concrete substructures. The condition was entered into the corrective action program. The shear displacements damaged conduit inside of the ductbank. The cause of the shear displacement was attributed to a loss of backfill material under the ductbank, which was not structurally adequate to span between the concrete substructures without the support of the backfill, when heavy loads were driven over the ductbank. The backfill was replaced and the replacement ductbank was designed with a higher load capacity. The loss of backfill was attributed to subsurface groundwater flow in saturated soil. Yard sumps are now being used to minimize groundwater levels to reduce the potential for loss of fill material. The loss of fill material was determined to also be the cause of pipe displacements in the Reactor Building. The fill material was replaced using a low strength concrete. The pipe supports were readjusted after the replacement of the fill material. Subsurface investigations were performed of similar areas and no voids were identified. Recurring inspections of the areas and the affected pipe supports were performed to confirm that further significant displacements are not occurring, and significant displacements have not been identified.

This operating experience provides objective evidence of the following: a) pipe supports are inspected and the inspections are effective at identifying degradation; b) inspections are performed to determine the extent of degraded conditions; c) degraded conditions are evaluated to determine the cause, impact on required functions, and corrective actions taken to ensure long term integrity, which may include configuration changes; and d) follow-up inspections are performed to verify the effectiveness of corrective actions.

3. Inspections are performed on underwater supports within the scope of the ASME Section XI, Subsection IWF aging management program inside each torus, inside the service water pump bays in the Circulating Water Pump Structure, and inside the inside the Emergency Cooling Tower and Reservoir. The following are some examples of the results of these inspections.

Inspections of underwater main steam relief valve (MSRV) T-quencher supports have been performed inside of each torus during the fourth ISI inspection interval. An inspection in 2014 of two supports in Unit 2 and an inspection in 2015 of two supports in Unit 3 did not reveal any relevant indications. During the second ISI inspection interval, inspection of five MSRV discharge line supports in Unit 2 and nine MSRV discharge line supports in Unit 3 did not reveal any relevant indications.

In 2013, diving inspections inside the Unit 3 torus identified a missing strut from the HPCI turbine exhaust pipe diffuser. It was determined that a cotter pin had corroded, subsequently allowing a turnbuckle to loosen during system operation. The strut was repaired and the support returned to service. The condition was evaluated and it was determined that the remaining supports were adequate to support operability of the system. A follow-up inspection in 2015 did not identify any deficiencies with the struts. As a result of the condition found in Unit 3, an inspection of the Unit 2 HPCI turbine exhaust diffuser struts was performed. In 2014, diver inspections inside the Unit 2 torus identified a missing cotter pin but the strut was still in place for the HPCI turbine exhaust pipe diffuser. It was determined that a cotter pin had corroded. The cotter pin was replaced.

Diver inspections of the emergency cooling water pump suction bell inside the Emergency Cooling Tower and Reservoir are also performed. The inspection in 2014, which included the pump casing, bolting, and seismic supports, documented that no abnormalities were identified and revealed that the bracing and struts were in good condition.

This operating experience provides objective evidence that inspections of the submerged portions of the supports within the scope of this program are performed and the inspections are adequate to identify degradation. When degraded conditions are identified, corrective actions are taken and the extent of identified degraded conditions are addressed prior to a loss of intended function.

4. The scope of the examinations for piping and component supports includes base plates and expansion anchors. The example below describes the identification of unsatisfactory results at a support on the steam supply piping to the HPCI turbine pump due to failures of anchor bolts, an evaluation to determine the cause of the failures, inspection scope expansion, support repair, and follow-up inspection.

In 2013, support plates for a HPCI system piping support in the Unit 3 Reactor Building were identified as pulled away from the ceiling and the anchor bolts were loose. Following the discovery of this condition, a post-transient walkdown was performed of all downstream supports and three upstream supports to determine if any additional supports were damaged. This walkdown did not identify any additional damage that could be related to the damaged support plates and anchor bolts. In addition, the scope of the examinations was expanded in accordance with IWF-2430 to include two adjacent supports and four additional supports of the same type and function. All expanded scope examination results were satisfactory, therefore no further examinations were required. The potential causes of the damage to the support plates and anchor bolts were identified, and it was concluded that it was not due to a water hammer event because only the one support was damaged. The support was repaired in 2013 prior to the end of the outage and follow-up examination in 2015 confirmed that the support was in satisfactory condition.

This operating experience provides objective evidence of the following: a) pipe supports are inspected and degradation identified; b) inspections are performed to determine the extent of degraded conditions; c) degraded conditions are evaluated to determine the cause to the extent possible; d) corrective actions taken to ensure long term integrity; and e) follow-up inspections are performed to verify the effectiveness of corrective actions.

The operating experience relative to the ASME Section XI, Subsection IWF program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, loss of mechanical function, and loss of preload. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI, Subsection IWF program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the ASME Section XI, Subsection IWF program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced ASME Section XI, Subsection IWF program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.32 10 CFR Part 50, Appendix J

Program Description

The 10 CFR Part 50, Appendix J aging management program is an existing condition monitoring program that manages the loss of material, loss of leak tightness, cracking, and loss of bolting preload in the containment and various systems penetrating primary containment. The program also detects loss of sealing due to degradation of elastomer gaskets and seals. The program manages steel and stainless steel containment structural elements, concrete embedments, penetration sleeves, hatches, airlocks, and bolting in air-indoor uncontrolled and treated water environments.

The program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, NEI 94-01, Revision 2-A and Revision 3-A, "Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," and subject to the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”

Containment leak rate tests are performed using plant procedures to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B and station Primary Containment Leakage Rate Testing Program. Local leak rate tests (LLRT) are performed on primary containment isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B and station Primary Containment Leakage Rate Testing Program. Components required to be leak rate tested or excluded from testing are identified in UFSAR Table 5.2-2. The ASME Section XI, Subsection IWE (B.2.1.30) program, External Surfaces Monitoring of Mechanical Components (B.2.1.24) program, Compressed Air Monitoring (B.2.1.14) program, One-Time Inspection (B.2.1.21) program, Water Chemistry (B.2.1.2) program, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program, BWR Stress Corrosion Cracking (B.2.1.5) program, ASME Code Class 1 Small-Bore Piping (B.2.1.23) program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program and the Flow-Accelerated Corrosion (B.2.1.9) program are included among the aging management programs that manage the aging effects associated with components excluded from leak rate testing. General visual inspection of the accessible interior and exterior surfaces of the containment structures and components are performed in conjunction with the ASME Section XI, Subsection IWE (B.2.1.30) program.

Monitoring and trending is performed by comparing valve and penetration leakage from test results to administrative leakage limits that are set lower than the regulatory acceptance criteria. Test or inspection results that do not satisfy established criteria are entered into the corrective action program for evaluation or repair.

NUREG-2191 Consistency

The 10 CFR Part 50, Appendix J aging management program is consistent with the ten elements of aging management program XI.S4, "10 CFR Part 50, Appendix J" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the 10 CFR Part 50, Appendix J program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the Primary Containment Leakage Rate Testing Program as described in UFSAR Section Q.1.10, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of existing Primary Containment Leakage Rate Testing Program is being effectively implemented during the first period of extended operation. The intent of the Primary Containment Leakage Rate Testing Program is to manage the loss of material for systems penetrating the primary containment and change in properties including cracking of gaskets and seals for the primary containment pressure boundary access penetrations.

The aging management program effectiveness review included a review of surveillance tests and maintenance history for activities completed between 2006 through 2016, and a review of operating experience within the corrective action program for identified age-related degradation of in scope components from 2001 through 2016. The inspections performed in accordance with the Primary Containment Leakage Rate Testing Program have identified age-related deficiencies associated with internal valve seat leakage of primary containment isolation valves and degradation of gaskets and seals associated with primary containment pressure boundary access points. These deficiencies have been identified during performance of leak rate testing of components in accordance with 10 CFR 50, Appendix J. The results of these inspections were evaluated under the corrective action program, which provided the mechanism for repair to achieve acceptable leakage results. These inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of this aging management program. This aging management program effectiveness review determined that the program is being implemented in accordance with the Primary Containment Leakage Rate Testing Program as described in UFSAR Section Q.1.10.

This operating experience provides objective evidence that the current Primary Containment Leakage Rate Testing Program is effectively managing aging effects of components that make up the primary containment boundary. Continued implementation of the 10 CFR 50, Appendix J aging management program will assure that components within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. The adjusted as-left leakage rate for Unit 2 following the 2014 ILRT was 0.237 La; and for Unit 3 the adjusted as-left leakage rate following the 2005 ILRT was 0.287 La. These tests were the most recent ILRT performed on Unit 2 and Unit 3. Both of these results are well below the maximum limit of 0.7 La (where La is the maximum allowable as-left primary containment leakage rate in percent weight per day) allowed by the Technical Specifications. These results show that in scope components that make up the primary containment boundary are being adequately maintained and that significant safety margin is maintained between the Technical Specifications allowable limits and the as-tested values.

This example provides objective evidence that the 10 CFR Part 50, Appendix J program effectively manages leakage from the primary containment and systems and components that penetrate primary containment, to ensure that the measured leakage rates do not exceed allowable leakage rate values as specified in the Technical Specifications and associated bases.

3. A Focused Area Self-Assessment (FASA) for the PBAPS Appendix J program was conducted in 2014. The purpose of the FASA was to evaluate compliance of the program with the requirements of 10 CFR 50 Appendix J Option B, Regulatory Guide 1.163, ANSI/ANS 56.8, NEI 94-01, Revision 2-A and Revision 3-A and Exelon program guidance. Industry and plant operating experience was considered in performance of the assessment. The FASA concluded that the program was effective with no deficiencies identified. Four recommendations were identified, and one strength was identified, which included administrative procedural enhancements and recommendations for requirements for testing of test tap valves. Activities were assigned to track implementation of the recommendations. The assessment provides evidence that industry and plant operating experience reviews are performed and that program procedural compliance is achieved.

This example provides objective evidence that the 10CFR Part 50, Appendix J program effectiveness is critically assessed resulting in self-identified actions that support continuous improvement.

4. In 2016, during the Unit 2 refueling outage, local leak rate testing identified that an inboard main steam isolation valve (MSIV) had through-valve leakage which exceeded its Technical Specification leakage criteria limit. Damage was found to the valve poppet. This condition was entered into the corrective action program, the valve was repaired, and the local leakage rate testing was re-performed successfully prior to startup from the outage. In addition to the

maintenance repairs, the MSIV design was improved by installing a modification that stabilizes and holds the poppet firmly in place during operation, thus reducing the rotational forces imparted on the valve internals that resulted in the internal valve damage and through-valve leakage.

This example provides objective evidence that components exceeding the allowable leakage rate acceptance criteria are being entered into the corrective action program, evaluated, repaired, enhanced, as needed, through design change process, and subsequently retested in accordance with the 10 CFR Part 50, Appendix J program.

5. NRC Information Notice 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. Bellows on the vent lines between the drywell and the torus and bellows on various drywell pipe penetrations are the two categories of primary containment bellows at PBAPS.

The bellows listed in UFSAR Table 5.2.2, "Containment Penetrations Compliance with 10 CFR 50, Appendix J," are local leak rate testable bellows and are local leak rate tested in accordance with 10 CFR 50, Appendix J, Option B, Type B testing. Local leak rate test procedures for containment expansion bellows include verification of flow through the annulus between plies of the bellows, which ensures that restrictions between the plies that could conceal a leakage path do not exist. A review of leakage test records since June 1977 has revealed no failures of these bellows.

This example provides objective evidence that industry operating experience is being reviewed and evaluated to confirm that station testing procedures are effective to maintain containment integrity.

The operating experience relative to the 10 CFR Part 50, Appendix J program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of leak tightness, loss of material, loss of sealing, and loss of preload. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the 10 CFR Part 50, Appendix J program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the 10 CFR Part 50, Appendix J program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The existing 10 CFR Part 50, Appendix J program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.33 Masonry Walls

Program Description

The Masonry Walls aging management program is an existing condition monitoring program implemented as part of the current Structures Monitoring program. It is based on the guidance provided in IE Bulletin 80-11, “Masonry Wall Design," and NRC Information Notice 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," and is implemented through station procedures.

The Masonry Walls aging management program manages inspections of masonry walls for loss of material and cracking, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. Environments include air-indoor uncontrolled and air-outdoor. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of license renewal so that the established evaluation basis for each masonry wall remains valid during the second period of extended operation. Masonry walls that are considered fire barriers are also managed by the Fire Protection (B.2.1.16) program.

The objective of the Masonry Walls aging management program is to manage aging effects of loss of material and cracking of masonry units and mortar, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. Conditions found to be “acceptable with deficiencies” or deemed to be “unacceptable” are documented and entered into the corrective action program for evaluation, which results in analysis, repair, or replacement, as necessary. Nonsafety-related masonry walls, with a structural intended function in structures that are in scope for second license renewal, are also inspected as part of the Masonry Walls aging management program.

The current Structures Monitoring program, which includes masonry walls, was developed and implemented to meet the regulatory requirements of 10 CFR 50.65, the Maintenance Rule, USNRC Regulatory Guide 1.160, and NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. Steel end supports and steel bracings are part of the masonry wall design and are considered as component supports and aging effects are managed by the Structures Monitoring (B.2.1.34) program. The PBAPS design includes safety-related and nonsafety-related masonry walls.

NUREG-2191 Consistency

The Masonry Walls aging management program will be consistent with the ten elements of aging management program XI.S5, "Masonry Walls" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program element:

1. Expand the program to include masonry walls in the Administration Building and Dewatering Building. **Program Element Affected: Scope of Program (Element 1)**

Operating Experience

The following examples of operating experience provide objective evidence that the Masonry Walls program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the portion of the Maintenance Rule Structural Monitoring Program, described in UFSAR Section Q.1.16, that manages Masonry Walls, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management program, that is to identify and correct age-related degradation of masonry walls, is being effectively implemented in the first period of extended operation. In the first license renewal period of extended operations, the Maintenance Rule Structural Monitoring Program included implementing activities that inspected and managed in scope masonry walls. The program effectiveness review was comprised of a review of the results of the structures monitoring inspections that are administratively divided into 387 different areas for the purposes of documenting the inspections. The structures monitoring inspections include the masonry wall inspections and issues addressed in the corrective action program for age-related degradation of in scope masonry walls. Minor degradation of masonry walls was identified in 17 of the 387 different areas included under the structures monitoring inspections. A review of masonry wall inspection results and issues in the corrective action program from 1996 through 2016 determined that:

- Degradation of masonry walls was identified and documented. Seventeen rooms were identified with degraded masonry walls. Fifteen of these walls were in the Turbine Building, one was in the Radwaste Building, and one in the Reactor Building. The degraded walls had issues with cracks in degraded mortar joints or gaps at the joints with adjacent walls. Two areas in the Turbine Building were identified with cracks in the masonry blocks. Four walls in the Turbine Building had degradation at penetrations, such as cracking or spalls.

- The masonry wall conditions were evaluated. There has been no masonry wall degradation to a degree requiring a change to the evaluation basis during the time period from 1996 through 2016.

- The configuration control process is used to address the addition of any new loads on masonry walls.
- Minor repairs to masonry walls are performed under the corrective action program. No structural repairs were required to restore the structural capacity of any walls. Repairs to masonry walls were performed to maintain the fire barrier function.

At PBAPS, ongoing inspections of the masonry walls under the Maintenance Rule Structural Monitoring Program, which includes the lessons learned from NRC IEB 80-11 and NRC IN 87-67, have not revealed any significant, recent cracking that might affect the evaluation basis. These findings are consistent with the age of the masonry walls, that the masonry walls were previously inspected and re-evaluated when necessary in response to IEB 80-11 and IN 87-67, and that the environmental conditions are relatively mild. The review identified that age-related degradation of in scope masonry walls is identified through the performance of inspections. Age-related issues are evaluated within the Maintenance Rule Structural Monitoring Program and corrected within the corrective action program. Therefore, the aging management program effectiveness review determined that the first license renewal Maintenance Rule Structural Monitoring Program, which includes masonry wall inspection and aging management activities, is being implemented in accordance with UFSAR Section Q.1.16.

This operating experience provides objective evidence that the inspections, maintenance practices, and the corrective action program effectively monitor the condition of masonry walls to assure that masonry walls will be able to continue to perform their intended functions and that appropriate aging management program activities will continue to be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that the Masonry Walls aging management program has effectively managed shrinkage, separation, gaps, loss of material, and cracking of masonry walls such that the evaluation basis is not invalidated.

2. In response to NRC IEB 80-11 "Masonry Wall Design", issued by the NRC in 1980, an analysis of a masonry wall, which divides the rooms for the Unit 2 and Unit 3 condensate phase separator pumps in the Radwaste Building, was performed, considering the masonry wall supported at the top, bottom, and both sides.

This masonry wall was inspected in 1987 in conjunction with the inspections addressed in NRC IN 87-67. As part of the inspection in 1987, vertical cracks were observed at the joints between the masonry wall and adjacent concrete walls. The masonry wall was re-evaluated to justify the functional adequacy of the masonry wall. As part of the re-evaluation in 1987, the evaluation basis of the wall was changed to only consider the masonry wall supported at the top and bottom, and no longer on the sides, due to the vertical cracks.

In April 2014, as part of the structures monitoring inspections, a vertical hairline crack was identified in this masonry wall that divides the rooms for the Unit 2 and Unit 3 condensate phase separator pumps in the Radwaste Building. This crack was documented in the structures monitoring program documentation and in the corrective action program. The hairline crack was evaluated and it was determined to be a normally expected imperfection and that there was no potential impact on the structural integrity of the wall. The crack is being monitored to identify significant changes in the crack.

This example provides objective evidence that inspections are used to monitor the condition of masonry walls, aging effects are entered into the corrective action program, and are evaluated. Aging effects and deficiencies are compared to the evaluation basis to ensure that the evaluation basis for the masonry wall remains valid. Corrective actions are developed as needed, to account for degraded conditions, such as repairs or adjusting the evaluation basis.

3. In March of 2009, an engineering change was implemented to upgrade the filter sludge system in the Radwaste Building, which included adding new pipe supports on the masonry walls in the rooms for the Unit 2 and Unit 3 condensate phase separator pumps. The masonry walls were evaluated for the additional loads and found to have adequate capacity.

This example provides objective evidence that when design changes are performed that affect the existing physical condition of a masonry wall, the configuration control process is used effectively to ensure that the evaluation basis for the masonry wall remains valid.

4. In February of 2016, a grout repair of a masonry wall crack was performed in the Unit 3 turbine lube oil room, which is adjacent to the control room in the Turbine Building. The repair of the nonsafety-related masonry wall was a result of a fire barrier inspection of the masonry wall. The results did not meet the acceptance criteria, so the condition was entered into the corrective action program, and the masonry wall was repaired to an acceptable condition.

This example provides objective evidence that results that do not meet acceptance criteria are addressed under the corrective action program, cracks are repaired in nonsafety-related masonry walls, and that nonsafety-related masonry walls are being managed by the Masonry Walls aging management program. In addition, this example provides objective evidence that inspections of masonry walls that are considered fire barriers by the Fire Protection (B.2.1.16) program are also effective at identifying aging effects.

5. The Masonry Walls aging management program is implemented as an element of the Structures Monitoring program, which is monitored under the Maintenance Rule. The Maintenance Rule implementation procedure includes steps to monitor plant-specific performance data and to evaluate industry operating experience. A Maintenance Rule program health report in 2016 concluded that the structures monitoring program was acceptable based upon all structures in the scope of the program, which includes masonry walls, being in acceptable condition.

This example provides objective evidence that the overall Structures Monitoring program, which includes the Masonry Walls program, is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience.

The operating experience relative to the Masonry Walls program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including shrinkage, separation, gaps, loss of material, and cracking of masonry walls. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Masonry Walls program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Masonry Walls program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Masonry Walls aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.34 Structures Monitoring

Program Description

The Structures Monitoring aging management program is an existing condition monitoring program that consists of periodic visual inspection and monitoring the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, SEI/ASCE 11, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Quantitative results (measurements) and qualitative information from periodic inspections are trended with sufficient detail, such as photographs and surveys for the type, severity, extent, and progression of degradation, to ensure that corrective actions can be taken prior to a loss of intended function. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative evaluation criteria of ACI 349.3R. Inspection frequency for the in scope structures will not exceed five years, with provisions for more frequent inspections when conditions are observed that have a potential for impacting an intended function. Unacceptable conditions, when found, are evaluated or corrected in accordance with the corrective action program. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation to ensure there is no loss of intended function.

The Structures Monitoring aging management program was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes elements of the Masonry Walls (B.2.1.33) program and Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) program.

Concrete structures are inspected for indications of deterioration and distress including evidence of leaching, loss of material, cracking, and a loss of bond, as defined in ACI 201.1R. Steel components are inspected for loss of material due to corrosion.

Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls.

The program also includes provisions for periodic testing and assessment of groundwater chemistry and opportunistic inspections of accessible below grade concrete structures.

Protective coatings are not relied upon to manage the effects of aging for structures included in the scope of this program. A de-watering system is not relied upon to control settlement and porous concrete was not used in the design of foundations.

Applicable components within the scope of this program include, but are not limited to: bolting, concrete anchors and embedments, concrete components, decking and siding, doors and door seals, ductbanks, expansion and seismic joints, foundations, hatches, hazard barriers, metal components such as flashing and louvers, miscellaneous steel, penetrations seals and sleeves, piles, pipe whip restraints and jet impingement shields, shielding, spent fuel pool gates, steel components, steel liners, supports, panels, racks, cabinets, enclosures, cable trays, conduits, wire way gutters, and tubing track.

Applicable metallic materials within the scope of this program include: aluminum, carbon steel, ductile iron, galvanized steel, and stainless steel; applicable bolting materials include: aluminum, brass, carbon steel, galvanized steel, and stainless steel. Applicable non-metallic materials within the scope of this program include: reinforced concrete, elastomer, fiberglass, grout, and Lubrite.

Applicable environments within the scope of this program include air-outdoor, air-indoor uncontrolled, treated water, raw water, water-flowing, and groundwater and soil.

Applicable aging effects within the scope of this program include change in material properties/ loss of strength, cracking, loss of material, loss of mechanical function, loss of preload/ self-loosening, and loss of sealing.

NUREG-2191 Consistency

The Structures Monitoring aging management program will be consistent with the ten elements of aging management program XI.S6, "Structures Monitoring" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Explicitly include the following components and commodities within the scope of the program:

   a. Bearing pads for supports
   b. Electrical duct banks
   c. Electrical raceway such as cable tray, conduit, and wireway gutter
   d. Hatches and plugs
   e. Manholes and handholes
   f. Miscellaneous components such as louvers
   g. Panels, racks, frames, cabinets, and other enclosures

h. Permanent shielding blankets

Program Element Affected: Scope of Program (Element 1)

2. Add the following structures to the scope of the program:
   a. Administration Building
   b. Boiler House
   c. Dewatering Building

Program Element Affected: Scope of Program (Element 1)

3. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation. **Program Element Affected: Monitoring or Trending (Element 5)**

4. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R. **Program Element Affected: Acceptance Criteria (Element 6)**

5. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), and Detection of Aging Effects (Element 4)**

7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**

8. Expand the program to monitor accessible sliding surfaces for indications of

significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant loss of material due to wear or corrosion, and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Acceptance Criteria (Element 6)**

9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. **Program Element Affected: Detection of Aging Effects (Element 4)**

10. Expand the program to monitor elastomeric vibration isolators and bearing pads for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection to detect hardening, if the intended function is suspect. Establish acceptance criteria for elastomeric pads and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of isolation or support function. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)**

11. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations. **Program Element Affected: Acceptance Criteria (Element 6)**

12. Expand the program to inspect the fiberglass outer covering of permanent shielding blankets for signs of tears. If a tear is found, enter the condition into the corrective action program for evaluation. Repair or replace the permanent shielding, unless an evaluation determines that the condition is acceptable. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Structures Monitoring program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed of the Maintenance Rule Structural Monitoring Program as described in UFSAR Section Q.1.16, and the Door Inspection Activities as described in UFSAR Section Q.2.6, in support of preparing the license renewal application for second license renewal. The purpose of the program effectiveness review was to verify the intent of the existing aging management activities, which is to identify and correct age-related degradation of structures and structural elements within the scope of the programs, is being effectively implemented in the first period of extended operation. The program effectiveness review was comprised of a review of the Maintenance Rule program health reports, structures monitoring implementing procedures, inspections results, and issues addressed in the corrective action program (CAP) for age-related degradation of structures and

structural elements. The program provides for visual inspections and surveys of all structures within the scope of the first license renewal. The in scope structures were split into 387 separately identified areas. The inspection results for the different inspections in the same areas were collated so that current inspection results could be compared to previous inspection results. Degradation of structures and structural elements was identified in 96 of the 387 different areas included under the structures monitoring inspections. The degradation is recorded, compared to previous results, reviewed and evaluated by qualified personnel, and significant degradation is entered into the corrective action program to initiate corrective actions such as repairs or replacements, more frequent inspections, more detailed evaluations, or design changes.

A review of the inspection results and issues in the corrective action program from 1996 through 2016 determined that:

- Degradation was identified and documented.
- Structural repairs are performed under the corrective action program.
- Accessible areas are inspected nominally every four years. In 2017, a review revealed that some accessible areas were inspected at intervals exceeding four years by up to five months. This condition was entered into the corrective action program and actions planned to ensure that inspection frequency limits are met.
- Inspections in inaccessible areas are tracked in the corrective action program and are performed when the areas become accessible.

Ongoing inspections and evaluations have not revealed results that would challenge an intended function. The performance of inspections and evaluation of issues in the corrective action program have resulted in the effective implementation of the aging management program.

As another example demonstrating the effective use of the Maintenance Rule program to manage the aging effects of structures, in 2008, when the dikes around the Unit 3 condensate storage tank had degraded due to excessive debris, a Maintenance Rule (a)(1) classification was assigned to the dikes under the Maintenance Rule program, and corrective actions initiated. As a result, corrective action and monitoring plans were developed, and the condition corrected.

To provide objective evidence of continuing improvements in the implementation of the structures monitoring program, a review of the Maintenance Rule health reports from 2011 to 2016 found that all structures are in a Maintenance Rule (a)(2) status, meeting functional requirements. Since 2015, a new section was added to the Maintenance Rule program health reports to specifically address structures monitoring results to enhance the visibility of the structures monitoring program within the overall Maintenance Rule program. As an example of ensuring that in scope components are included in the scope of the Maintenance Rule program, in 2011, a focused area self-assessment identified a concern at another nuclear power plant regarding whether pipe whip restraints were included within the scope of the

Maintenance Rule program. The concern was entered into the corrective action program to evaluate the applicability at PBAPS, and pipe whip restraints were then explicitly listed in the structures monitoring program.

The program effectiveness review determined the first license renewal Maintenance Rule Structural Monitoring Program and Door Inspection Activities aging management activities are being implemented as documented in UFSAR Sections Q.1.16 and Q.2.6.

This operating experience provides objective evidence that the existing Structures Monitoring program effectively monitors and manages the condition of structures, and that deficiencies are entered in the corrective action program. Continued implementation of the Structures Monitoring aging management program will assure that the structures and components within the scope of the program will continue to perform their intended functions during the second period of extended operation.

2. The Unit 2 and Unit 3 spent fuel pool tell-tail drainage systems have been monitored and there has not been significant leakage from the spent fuel pools. The spent fuel pool gate seals are inspected by maintenance personnel to provide assurance of gate integrity. In 2007, as a result of these inspections, the Unit 3, inner spent fuel pool gate seals were replaced. At Unit 2, there have been no notable instances of spent fuel pool leakage identified during the time period frame from 2003 to 2016. Several instances of minor leakage from the Unit 3 spent fuel pool are discussed below.

At Unit 3, relatively insignificant, intermittent leakage from the spent fuel has been observed at the tell-tale drains. In October 2001, when spent fuel pool water level was high during a refueling outage, a suspected spent fuel pool leak of 150 to 180 drops per minute was identified at the tell-tale drain. The spent fuel pool level was lowered, and the leak stopped two weeks after it was initially identified. No leak path through the spent fuel pool liner was positively identified. No signs of spent fuel pool leakage were observed during the subsequent refueling outage in 2003. In August of 2013, after using the RHR system in an off-normal system line-up, a suspected spent fuel pool leak of 60 drops per minute was identified at the tell-tale drain. During subsequent troubleshooting, as the spent fuel pool level was lowered and system line-ups varied, leakage varied between zero to 170 drops per minute, and eventually ceased by September of 2013. The source of this insignificant leakage was not positively identified. At the end of November of 2016, a suspected spent fuel pool leak was identified at the tell-tale drain with a rate of nine drops per minute. The leakage was monitored and subsequently stopped by the end of December 2016. Although the source of the spent fuel pool leakage was not identified, the leakage has been limited to periods with high spent fuel pool water levels and off-normal system line-ups as described above.

This operating experience provides objective evidence that the potential for spent fuel pool leakage is being monitored to assure that intended functions are maintained.

3. Plant operating experience was reviewed to identify instances of water infiltration into plant structures, and to assess any impact on the functions of in

scope structures. Water infiltration into the plant is addressed through inspections and corrective actions, and monitoring is in place to ensure that the effects are insignificant. Several examples are provided below.

In 1997, the external penetration seal designs for five below-grade penetrations were modified due to leakage into the building that was occurring following heavy rain storms. In response to groundwater infiltration identified in 2003 and 2009, the monitoring program was evaluated and significant structural effects were not identified. It was concluded that the existing structures monitoring practices should be continued and that the leakage was a housekeeping concern that could be addressed by generating corrective maintenance activities to minimize the housekeeping impacts when the leakage was significant. In 2015, minor leakage was identified at a penetration, and the condition of the penetration was evaluated. The evaluation documented that the construction specifications allow for minor leakage and it was concluded for this specific penetration that the design basis flood barrier function of the penetration was not impaired by the minor leakage.

In 2009, the structures monitoring program inspections identified and evaluated insignificant losses of material on embedded plates and conduits due to groundwater infiltration through concrete walls, as documented in the structures monitoring inspection database and corrective action program. No indications of concrete degradation due to groundwater infiltration have been identified.

In 2000 through 2001, an initiative aimed at addressing chronic roof leaks was completed that replaced many of the roofs on in scope structures. The reroofed structures included the Reactor Buildings, Turbine Buildings, Emergency Cooling Tower and Reservoir, Circulating Water Pump Structure, Administration Building, and the start-up and switchgear buildings, among others. In addition, a corporate long-term asset management strategy has been created to address roofing replacements across the Exelon fleet to assure roofs are maintained in good condition.

In 2003 and 2013, the High Pressure Service Water System valve pit covers were removed to allow for internal inspections of the concrete, as the valve pit can become flooded at high river level conditions. The concrete was found to be in good condition. In 2016, manholes 89A and 89B, which had a history of high water levels, were refurbished by replacing the divider plates and support brackets due to loss of material and sealing the concrete cracks to minimize water intrusion. In 2011, 2015, and 2016, the concrete was exposed during excavations near the Reactor Building, condensate storage tank, and for installation work associated with the Reactor Recirculation System adjustable speed drive project. The concrete walls were sound, were not cracked, and did not exhibit any evidence of spalling.

This operating experience provides objective evidence that water infiltration into plant structures is addressed through inspections, conditions are monitored and evaluated, and corrective actions are taken to ensure functional requirements are met.

4. Plant operating experience was reviewed to identify instances of when

cracks in concrete structures were identified, the conditions were documented in the corrective action program, and the conditions evaluated. Cracks in concrete are addressed through Structures Monitoring program inspections and corrective actions, and minor cracks are monitored to ensure that the effects are insignificant. Several examples are provided below.

The concrete support structures at the bases of the high voltage towers were inspected in 2004 and 2009. Cracks were identified, the condition was documented in the corrective action program, and the conditions evaluated. The evaluation determined that the most likely cause of the cracks was shrinkage during original construction and the cracks propagated due to environmental exposure. It was determined that the capability of the concrete structures to support the towers is not currently impaired and that corrective actions should be performed to prevent further long-term degradation. The corrective actions, consisting of surface repairs by the application of protective coatings, were completed in 2005 and 2013. The future inspections of these structures under the structures monitoring program will ensure that the intended structural support function is maintained.

The concrete corbel that supports the end beam of the Unit 3 Turbine Building roof slab has cracked under the end beam. The crack was documented in the structures monitoring database in 1997, and in the corrective action program. The condition was evaluated and it was concluded that the probable cause is due to original design details and that there are sufficient available load paths to ensure no loss of overall structural function. The crack was monitored and no change to the condition was identified until 2012, when the crack width noticeably increased. The change in the condition was also documented in the corrective action program. Inspections continue at six-month intervals. Much narrower cracks have been observed under other beams along the Unit 3 corbel and under the corresponding Unit 2 corbel. Although no repairs are currently warranted, an initial repair plan has been developed and alternative repair designs are being considered in the event the option to repair the condition is chosen. There is an expansion joint at the ends of the beams on top of the corbel. Expansion joints and seismic gaps have been inspected, and no significant changes in the gaps have been identified.

This operating experience provides objective evidence that concrete structures are inspected and when is degradation identified the conditions are evaluated within the corrective action program to determine the cause and potential impact on required functions. Corrective actions including repairs or increased monitoring are taken to ensure intended functions are maintained

5. The inspection of doors is included within the scope of the Structures Monitoring aging management program. Initial inspection activities are performed by maintenance personnel and are credited by the Structures Monitoring program for detection of aging effects.

In 2015, water was identified at the Unit 2 start-up switch gear building door. The cause of the water was initially thought to involve the door seals. The condition was entered into the corrective action program. Further investigation revealed that the leak was due to a leak through a seam in the building exterior surface above the door. The seam was caulked to prevent further leakage.

In 2013, water leakage was identified on the floor inside an exterior watertight door to the Circulating Water Pump Structure. The condition was entered into the corrective action program. The door gaskets were verified to be adequate. Additional inspections revealed that the leak was occurring along the interface line between the grout above the door and the concrete wall, which was covered by the door frame. The caulk along the edge of the door frame had degraded and started to pull away, allowing for water to seep between the door frame and wall, freeze during the winter, and open up the interface between the grout and the concrete. The surface was resealed to prevent water intrusion. To address the potential extent of the condition, other exterior watertight doors were inspected and similar or significant degradation was not identified at the other doors.

In 2003, the bars for dogging watertight doors inside the Reactor Building would no longer retract due to small, broken welds that retain the pivot pins. The condition was entered into the corrective action program. The doors were repaired. As a follow-up activity, the adequacy of the door inspections was reviewed and verified that the current approach to replace pins exhibiting wear or deterioration is effective.

This operating experience provides objective evidence that the structures monitoring program inspection activities provide for managing the aging effects for in scope doors, in both outdoor and sheltered environments, to provide reasonable assurance that aging effects will be addressed prior to a loss of intended function.

6. The inspection of in scope structures outside of the power block in yard areas is included within the scope of the Structures Monitoring aging management program. Plant operating experience was reviewed to identify instances of when degraded structural elements in the yard were identified, that the conditions are documented in the corrective action program, and the conditions evaluated, and corrective actions taken to address the condition. An example is provided below.

In 2009, while performing work to replace a damaged cable, it was discovered that a ductbank west of the Reactor Building had experienced a shear displacement at the span over backfill, which was extending between concrete substructures. The condition was entered into the corrective action program. The shear displacements damaged conduit inside of the ductbank, damaging the cable. The cause of the shear displacement was attributed to a loss of backfill material under the ductbank, which was not structurally adequate to span between the concrete substructures without the support of the backfill, when heavy loads were driven over the ductbank. The backfill was replaced and the replacement ductbank was designed with a higher capacity. The loss of backfill was attributed to subsurface groundwater flow in saturated soil. Yard sumps are now being used to minimize groundwater levels to reduce the potential for loss of fill material. The loss of fill material was determined to also be the cause of pipe displacements in the Reactor Building. The pipe supports were readjusted after the fill replacement. Subsurface investigations were performed of similar areas and no voids were identified. Recurring inspections of the areas and the affected pipe supports were created to identify any further significant displacements, and none have been identified.

This operating experience provides objective evidence that when degradation of in scope structures are identified they are entered into the corrective action program, evaluated to determine the cause and impact on required functions, and corrected. The extent of condition is addressed and actions including follow-up inspections are performed to verify the effectiveness of corrective actions to ensure long-term integrity.

The operating experience relative to the Structures Monitoring program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of bond, and loss of material (e.g., due to corrosion, spalling, and scaling), and increase in porosity and permeability. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Structures Monitoring program are performed to identify the areas that need improvement to maintain the effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that the continued implementation of the Structures Monitoring program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Structures Monitoring program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.35 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is an existing condition monitoring program that consists of inspection and surveillance of the raw water control structures associated with emergency cooling systems, which are the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. In the event of the loss of the normal heat sink or when flooding occurs, the circulating pump structure sluice gates isolate the structure to allow for closed cycle operation, between the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir, through the use of the Emergency Cooling Water system. Therefore, the PBAPS design does not include dams, slopes, canals, and other raw water-control structures associated with emergency cooling water systems or flood protection in the scope of this program.

Structural components and commodities monitored under this program include steel bolting, concrete anchors and curbs; reinforced concrete members such as interior and exterior walls, slabs, beams, panels, columns, basemats, foundations and sub-foundations, hatches and plugs; as well as steel, concrete, and cast iron sluice gates; and equipment supports and foundations. The program also includes PVC drift eliminators, ceramic tile fill, and cast iron fill supports at the Emergency Cooling Tower and Reservoir. In addition, the program includes copper with more than 15 percent zinc for the seat facing of the sluice gates. Because of the plant design, there are no trash racks associated with emergency cooling water systems or flood protection that are in scope for second license renewal.

The program manages loss of material, loss of preload, cracking, loss of bond, increase in porosity and permeability, change in material properties, reduction in heat transfer, and reduction of strength. Environments include air-indoor uncontrolled, air-outdoor, raw water, and water flowing.

The program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect the intended functions of the water-control structures and components in the scope of this program. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent the loss of intended function due to significant age-related degradation. Elements of the program are designed to provide records of periodic inspections and evaluations of structural conditions to detect age-related deterioration and degradation and to initiate maintenance activities and corrective actions so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner.

In general, parameters monitored are in accordance with Section C.2 of U.S. NRC Regulatory Guide (RG) 1.127, "Inspection of Water Control Structures Associated with Nuclear Power Plants", and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. PBAPS is not currently committed to the requirements in NRC RG 1.127, but has been implementing the guidance of RG 1.127 for the structures in scope for license renewal through station procedures, work orders, and inspections. The aging management program is based on the guidance provided in NRC RG 1.127 and American Concrete Institute (ACI) 349.3R-02. Structures exposed to aggressive water require additional plant-specific investigation.

Structures located underwater will not be accessible for evaluation with the same level of visual acuity as structures above water. Inspections will be implemented that establish the condition of these structures by using divers or by dewatering, as well as by considering the conditions of the exposed portions of the structures, at the waterline and above, which can serve as an indicator of conditions underwater. These measures allow for the characterization of long-term aging effects to a level of detail that can be used to determine whether additional inspection measures are warranted, and to prioritize any further inspection or evaluation efforts so that this aging management program will be effective in assuring that intended functions of submerged structures are maintained consistent with the current licensing basis for the second period of extended operation.

Inspections are performed at least once every five years for structural components that are not submerged. Submerged components in the Circulating Water Pump Structure are inspected by divers or dewatered to allow for inspection at least once every six years. Submerged components in the Emergency Cooling Tower and Reservoir are inspected by divers or dewatered to allow for inspection at least once every 10 years. The inspection activities include cleaning of areas covered by silt, vegetation, or marine growth to allow for inspections. The raw water at PBAPS is not considered aggressive based on chemistry records that indicate pH, sulfates and chlorides are below the threshold limits to be considered aggressive. The inspections of submerged concrete structures within the scope of this program have not revealed any significant degradation, inspections of accessible concrete portions of the same concrete structures above the water and at the waterline have not revealed significant structural degradation, and the raw water is not aggressive. In addition, the Emergency Cooling Tower and Reservoir is currently only subjected to water flows during system testing so the exposure time of the submerged concrete to flowing, raw water is negligible compared to other concrete structures and the exterior portions of the reservoir that are accessible and visually inspected every two years. Based upon an assessment of the current conditions, no changes to current inspection frequencies have been identified to date and a maximum frequency of every five years is not warranted to manage submerged concrete aging during the second period of extended operation.

Not included in this program is the offsite Conowingo Hydroelectric Plant (Dam), which is operated under a separate license and is subject to the FERC five-year inspection program. Aging management for the dam includes activities such as visual inspections by a qualified independent consultant approved by FERC, and submittal of inspection reports with corrective actions that are approved by FERC. Aging management for the dam is performed in accordance with FERC requirements, and is in compliance with Title 18 of the Code of Federal Regulations, Conservation of Power and Water Resources, Part 12 (Safety of Water Power Projects and Project Works), Subpart D (Inspection by Independent Consultant). The inspections performed under the FERC five-year inspection program have been approved by FERC, and are the current licensing basis for PBAPS regarding aging management of the dam. PBAPS will continue to comply with these FERC requirements during the second period of extended operation.

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is implemented through the Structures Monitoring (B.2.1.34) program for the associated in scope structures.

NUREG-2191 Consistency

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be consistent with the ten elements of aging management program XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Explicitly include the sluice gates at the Circulating Water Pump Structure within the scope of the program. **Program Element Affected: Scope of Program (Element 1)**

2. Clarify parameters to be monitored and inspected at the Emergency Cooling Tower and Reservoir to include visual inspection for loss of material and reduction of heat transfer due to fouling for the cooling tower fill, and visual inspection of the drift eliminators. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

3. Monitor for reduction in concrete anchor capacity if local concrete degradation such as cracking and loss of material is identified. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

4. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

5. Include provisions for special inspections following significant natural phenomena, such as large floods, hurricanes, tornadoes, or intense local rainfall as part of the guidelines for severe weather and natural disasters. **Program Element Affected: Detection of Aging Effects (Element 4)**

6. Monitor raw water and ground water chemistry, for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from a location that is representative of the groundwater in contact with structures within the scope of second license renewal. Enter adverse results, which exceed water chemistry criteria, into the corrective action program. Develop engineering evaluations, on an interval not to exceed five years, to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. **Program Element Affected: Detection of Aging Effects (Element 4)**

7. Monitor and trend through-wall groundwater leakage, infiltration volumes, and leakage water chemistry for signs of concrete or steel reinforcement degradation. Develop additional engineering evaluations, which consider more frequent inspections, as well as destructive testing of affected concrete to validate existing concrete properties, and leakage water chemistry results. If leakage volumes allow, consider water chemistry analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. **Program Element Affected: Detection of Aging Effects (Element 4)**

8. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. **Program Element Affected: Detection of Aging Effects (Element 4)**

9. Document the concrete conditions of submerged concrete structures. **Program Element Affected: Detection of Aging Effects (Element 4)**

10. Specify a six-year frequency for the inspection of the submerged portions of the traveling screen bays to match the inspection frequency of the submerged portions of the Circulating Water Pump Structure bays. **Program Element Affected: Detection of Aging Effects (Element 4)**

11. Perform inspections under the enhanced program in order to establish quantitative baseline inspection data prior to the second period of extended operation. **Program Element Affected: Monitoring or Trending (Element 5)**

12. Provide evaluation criteria for structural concrete using quantitative second tier criteria of Chapter 5 in ACI 349.3R. **Program Element Affected: Acceptance Criteria (Element 6)**

13. Clarify that loose bolts and nuts and cracked bolts are not acceptable unless accepted by engineering evaluations. **Program Element Affected: Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed in support of preparing the license renewal application for second license renewal. The scope of review included the portion of the Maintenance Rule Structural Monitoring Program described in UFSAR Section Q.1.16; and the Outdoor, Buried and Submerged Component Inspection Activities program as described in UFSAR Section Q.2.5, which manage structures within the scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program. The purpose of the aging management program effectiveness review was to verify the intent of this existing aging management program, which is to identify and evaluate age-related degradation of water-control structures, is being effectively implemented in the first period of extended operation. In the first license renewal period of extended operations, the Maintenance Rule Structural Monitoring Program included implementing activities that inspected and managed the structures in scope for the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program. The program effectiveness review was comprised of a review of the results of the structures monitoring inspections that are performed at the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir. The program effectiveness review also included a review of the results of diver inspections in these structures, some of which are performed as part of the Open-Cycle Cooling Water System (B.2.1.11) program. In addition, pertinent issues found in the corrective action program were evaluated by searching for age-related degradation of in scope Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir.

A review of the inspection results and issues in the corrective action program from 1997 through 2016 determined that degradation was identified and documented and conditions were evaluated. The review found that only minor degradation, such as concrete spalling and cracking, steel corrosion, and roof leaks, were identified. Age-related issues were evaluated and corrected under the corrective action program resulting in effective implementation of this aging management program.

In 2013, operating experience at other sites was reviewed to determine alternatives for sodium chloride to prevent icing on the parking lot and walkways around the PBAPS site during the winter. The review for potential alternatives was performed to determine if there were practical alternatives that could be used that might cause less material degradation of reinforced concrete, while being cost-effective and effectively prevent icing. The review found insufficient justification to initiate an Exelon fleet-wide policy for using alternatives to sodium chloride.

Therefore, the aging management program effectiveness review determined that the Maintenance Rule Structural Monitoring Program and the Outdoor, Buried and Submerged Component Inspection Activities program, which include inspections and aging management activities for the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir, are being implemented in accordance with UFSAR Sections Q.1.16 and Q.2.5, respectively.

This operating experience provides objective evidence that the inspections, maintenance practices, use of operating experience, and the corrective action program effectively monitor the condition of water control structures to assure that water control structures will be able to continue to perform their intended functions and that appropriate aging management program activities will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that this aging management program has effectively managed loss of material, loss of preload, cracking, loss of bond, increase in porosity and permeability, change in material properties, reduction in heat transfer, and reduction of strength.

An effectiveness review was also performed to verify the Conowingo Dam aging management program is effectively implemented in the first period of operation. This aging management review was comprised of a review of the dam inspection reports. This review verified that aging management for the dam was being performed in accordance with FERC requirements, such as performance of visual inspections performed by qualified inspectors approved by FERC, and submittal of inspection reports with corrective actions that are approved by FERC. Therefore, the aging management program effectiveness review determined that the program is being implemented in accordance with the UFSAR Section Q.1.15, Conowingo Hydroelectric Plant (Dam) Aging Management Program.

2. Plant operating experience was reviewed to identify instances of when cracks in concrete of water-control structures were identified, the conditions were documented in the corrective action program, and the conditions evaluated. Cracks in concrete are addressed through inspections and corrective actions, and when the cracks are minor, continued monitoring is used to ensure that the effects of the cracks remain insignificant. Examples of concrete inspections are provided below.

The inspection of the Circulating Water Pump Structure and Emergency Cooling Tower and Reservoir is included within the scope of this program. The inspections of these structures were performed as part of the inspections under the Structures Monitoring aging management program. These above-water inspections have included steel and concrete elements. The concrete inspections have included the identification of concrete degradation and evaluation of the condition. No significant differences in concrete conditions have been identified at the waterline, which could be considered as a leading indicator of underwater conditions.

In 2011, a corporate review of NRC Information Notice 2011-20, Concrete Degradation by Alkali-Silica Reaction (ASR) was performed to determine if similar deficiencies existed across the Exelon fleet. This review included an analysis of the structures monitoring program inspection results at PBAPS, which concluded that the concrete structures had not exhibited the ASR-type cracking. In addition, the corporate structures monitoring procedure was updated to refer to IN 2011-20, and to add additional guidance for concrete inspections to identify indications of the presence of ASR.

The concrete conditions of the exterior of the Emergency Cooling Tower Reservoir have been subject to additional inspections. The Emergency Cooling Tower Reservoir is a leading indicator for concrete degradation because the interior surface is saturated with water and the exterior surface is subject to freeze-thaw conditions during the winter. Tight, vertical cracks in the concrete of the reservoir, some with water seepage and efflorescence, were identified in 1997. The condition was entered into the corrective action program, the condition evaluated, and determined to be acceptable due to the narrow crack widths, lack of rust stains, limited water flow through the cracks, and no evidence of offset of adjacent surfaces at the cracks. Mapping of cracks in the concrete at the reservoir was been performed in 2004, 2009, 2011, 2012, 2013, and 2015 to record the location, distribution, and orientation of the cracks. The results of the crack mapping have been reviewed and it has been concluded that there have been no significant changes in the cracks. The concrete conditions, which have included minor cracking and efflorescence, have been evaluated and the conditions were determined to be acceptable. A detailed assessment and evaluation of the reservoir concrete conditions was performed in 2013. This inspection included the following: 1) a general, visual assessment of accessible areas of the entire structure from the ground; 2) crack patterns were compared to previous crack maps and found to be generally consistent; 3) hammer sounding was performed of cracked concrete and no delaminated areas were identified; 4) ground penetrating radar was used to verify that reinforcement steel locations were consistent with the design drawings; and, 5) samples of efflorescence were taken and X-ray fluorescence spectrometry testing was performed to assist in determining the chemical constituents of the efflorescence, which was identified as typical calcium oxides of efflorescence with only trace amounts of iron oxides consistent with normal cement composition or might also indicate some rust corrosion products. The most likely cause of the concrete cracking is attributed to restrained volume changes of the concrete related to shrinkage and thermal movements and is not attributed to ASR due to the location and distribution of the concrete cracks.

This operating experience provides objective evidence that concrete structures are inspected and degradation identified. The conditions are evaluated to determine the cause, impact on required functions, and corrective actions taken to ensure long term integrity, such as repairs or increased monitoring. In addition, industry operating experience is used to inform the concrete inspections.

3. The inspection of the Circulating Water Pump Structure and the Emergency Cooling Tower and Reservoir includes submerged portions using divers or access is gained through dewatering the structure. The following are some examples of the results of these inspections.

Inspections of the emergency service water (ESW) pump bays in the Circulating Water Pump Structure are performed and the areas cleaned as necessary. Two examples for the Unit 2, “A” ESW bay are as follows: a) in 2016, silt levels were identified, and the areas were then cleaned to remove all silt; and b) a previous inspection in 2006 of the same Unit 2, “A” ESW bay revealed silt levels and the areas were then cleaned to remove all silt. Two examples for the Unit 3, “B” ESW bay are as follows: a) in 2015, silt levels were identified, and the areas were then cleaned to remove all silt; and b) a previous inspection in 2005 of the same Unit 3, “B” ESW bay revealed silt levels and the areas were then cleaned to remove all silt.

Inspections of the Circulating Water (CW) pump bays in the Circulating Water Pump Structure are performed and the areas cleaned as necessary. In 2016, diver inspections in the Unit 2 “B” CW pump bay revealed that underwater support members for components, which are not in scope for second license renewal, were broken due to corrosion of the anchors. The conditions were entered into the corrective action program. The stop logs were then installed in this pump bay, the pump bay dewatered, and repairs completed using stainless steel anchors. During this pump bay outage, the pump bay was also cleaned of minor marine growth. In 2017, diver inspections in the Unit 3 “B” CW pump bay revealed that underwater support members for components, which are not in scope for second license renewal, were broken, and the conditions were entered into the corrective action program. The stop logs were then installed in this pump bay, the pump bay dewatered, and repairs completed. During this pump bay outage, the pump bay was noted as clean with no silt to remove.

Diver inspections of the traveling screen bays in the Circulating Water Pump Structure have been performed to support the operation of the traveling screens. For example, in 2016 and 2017, the Unit 2 screen structure and wing walls were found to be in good condition.

In 2012, diver inspections of the sluice gates in the ESW pump bays in the Circulating Water Pump Structure discovered surface corrosion that was removed. Inspections in 2015 for Unit 3, and in 2016 for Unit 2, revealed that the sluice gates were in satisfactory condition.

Diver inspections inside the Emergency Cooling Tower and Reservoir at the emergency cooling water (ECW) pump suction bell are also performed. The inspection in 2014 revealed minor silt levels of 1 inch or less and that the underwater portions of the concrete columns were in good condition.

This operating experience provides objective evidence that the inspections of the submerged portions of the structures in the scope of this program are performed, the inspections are adequate to identify degradation, and corrective actions are taken to provide reasonable assurance that aging effects will be addressed prior to a loss of intended function.

The operating experience relative to the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of bond, and loss of material, increase in porosity and permeability, reduction in strength, and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.36 Protective Coating Monitoring and Maintenance

Program Description

The Protective Coating Monitoring and Maintenance aging management program is an existing mitigative and condition monitoring program which manages the effects of loss of coating integrity of Service Level I coatings inside the primary containment (as defined in Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.54, Revision 1 or latest revision) in air-indoor uncontrolled and treated water environments. The failure of the Service Level I coatings could adversely affect the operation of the emergency core cooling systems (ECCS) by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The Protective Coating Monitoring and Maintenance program includes coating system selection, application, inspection, assessment, maintenance, and repair for any condition that adversely affects the ability of Service Level I coatings to function as intended. Evaluations are performed for test or inspection results that do not satisfy established criteria and the conditions are entered into the corrective action program.

Service Level I coatings prevent or minimize the loss of material due to corrosion, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment shells and components. This program ensures only that the Service Level I coatings maintain adhesion so as to not affect the intended function of the ECCS suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of unqualified coating is controlled to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits.

NUREG-2191 Consistency

The Protective Coating Monitoring and Maintenance aging management program will be consistent with the ten elements of aging management program XI.S8, "Protective Coating Monitoring and Maintenance" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program elements:

1. Use certified coating inspectors for the inspection of Service Level I coatings. **Program Element Affected: Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Protective Coating Monitoring and Maintenance program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the aging management activities in place for components within primary containment that are coated with Service Level I coatings, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management activities, which is to monitor and maintain Service Level I protective coatings inside the primary containment to ensure that the condition of the subject coatings do not impact operability of the Emergency Core Cooling Systems (ECCS), is being effectively implemented in the first period of extended operation.

The program effectiveness review was comprised of a review of self-assessments, related ISI program health reports, operating experience, completed coating examination and inspection work records, maintenance activities, program implementing documents, as well as a review of pertinent issues found in the corrective action program. Information was collected from 2003 to 2016. The corrective action program was searched for coating issues to identify age-related degradation of Service Level I coatings inside the containments. Issues in the corrective action program from 2003 through 2016 included programmatic and procedural enhancements, degraded coatings, reporting issues for tracking unqualified coatings, and quality issues affecting torus recoating work.

The review identified that age-related degradation of the Service Level I coatings on SSCs is identified through the performance of periodic inspection activities. Age-related and programmatic issues are evaluated and corrected using the corrective action program, resulting in effective implementation of this aging management program. The review found that resolution of these corrective action program issues has resulted in adding degraded and unqualified coatings to the unqualified coatings log. In addition, the program effectiveness review determined that coating damage or degradation is properly documented and reported to the cognizant engineer for evaluation and disposition, and that periodic inspections and analysis of the total amount of degraded and unqualified coatings in the containments is properly compared with the total amount of permitted degraded and unqualified coating to support post-accident operability of the ECCS. These reviews also found that the station is actively monitoring, trending, and maintaining Service Level I coatings, including completion of recoating of the submerged areas of both tori in 2012 and 2013. The records verify the qualification of inspectors, coating applicators, and the coating system.

The Protective Coating Monitoring and Maintenance aging management program was not credited as a part of first license renewal; therefore, it is not addressed in the UFSAR, Appendix Q. Aging management activities to monitor and maintain coatings were established in 1999 in accordance with the Maintenance Rule in response to NRC Generic Letter 98-04, and a request for additional information from the NRC, regarding proposed alternatives to the requirements of 10 CFR 50.55 concerning the containment inservice inspection (CISI) program. Regulatory Position C.4 of NRC RG 1.54 endorses ASTM D5163-08 as guidelines for an acceptable in-service coating monitoring program and adds requirements including the use of qualified personnel, a nuclear coating specialist, as well as performing evaluation of degraded coatings for impact on the ECCS post-accident functions. The Exelon corporate procedure requirements include appropriate aspects of ASTM D5163-08, as well as requirements for personnel qualifications, and for identification and evaluation of degraded and unqualified coatings to ensure monitoring and maintenance of Service Level I coatings is comparable with NRC Regulatory Guide 1.54, Rev. 2, Position C.4.

This operating experience provides objective evidence that the inspections, maintenance practices, and corrective action program effectively monitor the ability of Service Level I coatings to perform their intended functions, and with implementation of the Protective Coating Monitoring and Maintenance aging management program, appropriate aging management will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that degraded and unqualified coatings have been effectively managed to ensure that the unqualified coatings in containment remain below the coatings debris allowance, thereby precluding the potential for clogging of the ECCS suction strainers and ensuring ECCS post-accident operability.

2. In 2012, as a result of previous monitoring and trending of coating condition, the Unit 2 Torus was drained, and the interior surface up to nominally one foot below the normal waterline was cleaned, prepared, and the coating was replaced with a qualified Service Level I coating. Due to the presence of a nominally two-foot wide epoxy band centered along the normal waterline that was previously applied on the interior of the torus shell and left in place, the new coating on the torus shell goes up to nominally one foot below the normal waterline. The remainder of the Service Level I coatings inspected were found acceptable and no other areas requiring recoating were identified.

During the following outage in 2014, a follow-up underwater coating inspection was performed to confirm the adequacy of the replacement coating. The inspection found the coatings in good condition with limited holidays and other spot corrosion issues which had already been identified in the corrective action program in 2012. The coating conditions were evaluated and corrected as necessary during the same outage.

This operating experience demonstrates that Service Level I coatings are inspected during refueling outages by qualified coating inspectors, inspection results are evaluated by the coatings coordinator, and coating maintenance including recoating is initiated to support continued operability of ECCS.

3. In 2013, as a result of previous monitoring and trending of coating condition, the Unit 3 Torus was drained, and the interior surfaces up to

nominally one foot above the normal waterline was cleaned, prepared and the coating was replaced with a qualified Service Level I coating. The remainder of the Service Level I coatings inspected were acceptable and no other areas requiring recoating were identified.

During the following outage in 2015, a follow-up underwater coating inspection was performed to confirm the adequacy of the replacement coating. This inspection found the coatings in good condition with limited holidays and other spot corrosion issues, which had already been identified in the corrective action program in 2013. The coating conditions were evaluated and corrected as necessary, during the same outage.

This operating experience demonstrates that Service Level I coatings are inspected during refueling outages by qualified coating inspectors, inspection results are evaluated by the coatings coordinator, and coating maintenance including recoating is initiated to support continued operability of ECCS systems.

The operating experience relative to the Protective Coating Monitoring and Maintenance program did not identify an adverse trend in performance. The inspection methods being implemented within the program have been proven effective in detecting aging effects including loss of coating or lining integrity. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Protective Coating Monitoring and Maintenance program are performed to identify the areas that need improvement to maintain the effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Protective Coating Monitoring and Maintenance program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Protective Coating Monitoring and Maintenance program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of the electrical insulation for license renewal in scope, non-EQ, electrical cables and connections during the second period of extended operation.

In most areas of PBAPS, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. An adverse localized environment (ALE) is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected in these adverse localized environments.

Accessible cables and connections located in adverse localized environments are managed by visual inspection. These cables and connections are visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture. This is an adequate inspection frequency to preclude failures of the cable and connection insulation since experience shows that aging degradation is a slow process.

Additional inspections, repairs, or replacements are initiated as appropriate under the corrective action program. If visual inspections identify degraded or damaged conditions that may impact the cable system’s ability to perform its intended functions, then testing may be performed for evaluation. Testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Testing as part of an existing maintenance, calibration or surveillance program may be credited. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the station’s procedures.

This existing program will be enhanced prior to the second period of extended operation. In addition, the first inspections incorporating enhancements will be completed prior to the second period of extended operation.

NUREG-2191 Consistency

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG 2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements.

1. Include potential follow-up actions when visual inspections identify degraded or damaged conditions that may impact the performance of intended functions:

   a. Perform tests, for condition monitoring, when visual inspections identify damaged or degraded insulation of in scope cables and connections. When a large number of cables are identified as damaged or degraded, a sample population will be tested. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25.

   b. Document the basis for the sample selected for testing when visual inspections identify damaged or degraded insulation conditions for in scope cables or connections.

Program Element Affected: Detection of Aging Effects (Element 4)

2. Visually inspect and evaluate cables and connections that were exposed to adverse localized environments (ALEs), which have since been mitigated, on an at least once every 10-year frequency, to assure the cumulative aging effects for electrical insulation, in remedied ALEs are not impacting the ongoing ability of the cables and connections to perform their intended function during the second period of extended operation. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the non-EQ electrical insulation for electrical cables and connections aging management activities in support of preparing the license renewal application for second license renewal. The electrical insulation included in this program effectiveness review is managed by the Non-EQ Accessible Cable Aging Management Activity as described in UFSAR Section Q.3.3 and FSSD Cable Inspection Activities as described in UFSAR Section Q.3.2, for first license renewal. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program

activities, to identify and correct, as warranted, age-related degradation of electrical insulation for electrical cables and connections, is being effectively implemented in the first license renewal period of extended operation. The original activities included identification of adverse localized environments, visual inspection of electrical insulation for accessible cables and connections, documentation of findings, and follow-up actions in the corrective action program.

The program effectiveness review was comprised of a review of visual inspection implementation activities to date and pertinent issues in the corrective action program, searching for identified age-related degradation of electrical insulation for electrical cables and connections. Pre-period of extended operation visual inspection results and issues in the corrective action program from 2003 through 2016 were reviewed. The reviews did not identify significant age-related degradation of electrical insulation for accessible electrical cables and connections that impacted the ability to perform intended functions. Only minor degradation of cable jackets that would not impact performance of intended functions was observed. In some ALEs, there were no observable conditions or changes for the electrical cable and connection insulation exposed to the ALE. These observations were made during performance of routine program implementation, maintenance, and modification work; correcting design and installation deficiencies with respect to equipment and piping insulation; and correcting environment conditions (e.g., leaks and uninsulated hot process pipes) to eliminate an adverse localized environment. Some follow-up actions were to perform re-inspections sooner than the program's 10-year frequency, specifically to ensure that observed degradation was not progressing at a faster than expected rate. The increased frequency inspections were primarily for cables within ALEs (where there was either no observable impact to the cable insulation or at most some fading of the cable jackets without cracked or broken insulation or exposed wires). Other follow-up actions were to replace degraded segments of cable. There were no issues in either the pre-period of extended operation implementation or the current period of extended operation related operating experience items, where an in scope cable was unable to perform its intended function due to age-related degradation. The performance of visual inspections and evaluation of issues in the corrective action program have resulted in the effective implementation of this aging management program. The program effectiveness review determined that the program is being implemented in accordance with UFSAR Sections Q.3.3 and Q.3.2.

This operating experience provides objective evidence that the visual inspections and the corrective action program effectively monitor electrical insulation for electrical cables and connections to assure that they will be able to continue to perform their intended functions and that appropriate aging management will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that this aging management program has effectively managed potential reduction in electrical insulation resistance for in scope, non-EQ, accessible, electrical cables and connections.

2. In 2016, during the performance of Unit 2 periodic maintenance to remove

acoustic monitor sensors for calibration in the hot shop, degradation was identified on pigtail cable outer jackets. This maintenance activity was not associated with aging management. The issue was entered into the corrective action program. The insulation degradation exposed intact, conductors. A loop check verified that the instrument loop was still intact and operating; there was no loss of intended function. It was determined that the cable needed to be repaired or replaced to ensure continued performance of intended function. Repair of the cables with EQ heat shrink was performed as part of the maintenance work order. Post maintenance calibrations after re-installation confirmed that the acoustic monitor was able to perform its intended function after the cable insulation repair. The work order involved numerous channels of acoustic monitor sensors. The cable degradation was limited to a single circuit most likely due to the physical manipulation associated with removing the sensor; therefore, no extent of condition evaluation was necessary. This operating experience was not part of program implementation but instead an example of good behaviors when a degraded condition was identified during maintenance activities.

This operating experience demonstrates worker awareness of the need to identify and correct age degraded cable electrical insulation and provides objective evidence that existing maintenance practices effectively identify observable cable jacket deficiencies and subsequently implement effective corrective action.

3. In 2015, during the performance of a modification to replace feedwater heaters, existing Unit 3 conduit and cables needed to be temporarily removed to facilitate the heater replacements. During the performance of this modification work, it was identified that there was degradation of the electrical insulation for the not in scope cables located in the conduit. The insulation degradation was due to the ALE and was entered into the corrective action program. A corrective maintenance work order was created to remove and replace the degraded cable sections. New cables were spliced into the existing circuits. This self-identified aging issue was entered into the corrective action program. Corrective actions were implemented per the corrective maintenance work order, concurrent with modification work, and replaced all cables in the conduit. This self-identified, electrical insulation, operating experience was not part of program implementation. It demonstrates good behaviors and worker awareness to identify and correct age degraded cable electrical insulation when identified during non-aging management activities.

This issue provides objective evidence that existing maintenance practices affectively identify observable cable jacket deficiencies and subsequently implement effective corrective actions.

4. In 2013, during the investigation and repair of a faulted nonsafety-related, not in scope for license renewal Unit 3, 480 V power cable, the extent of condition was evaluated for an adjacent power cable. This extent of condition was performed since the suspected cause of the faulted cable was environmental heat stress from adjacent main steam lines. It was determined that the adjacent cable may be subject to degradation due its proximity to the same environmental conditions, even though the adjacent cable did not have a

fault condition. An engineering change was prepared for replacement of the adjacent cable and was approved to be completed in an available system outage window during the next outage. The adjacent cable is also nonsafety-related and is not in scope for license renewal. The replacement cable has been installed. This self-identified, electrical insulation, operating experience was not part of program implementation.

This operating experience demonstrates organizational awareness to evaluate extent of condition for age degraded cable regardless of safety classification or license renewal scope determination and provides objective evidence that existing practices identify when extent of condition should be evaluated and as necessary, corrected.

The operating experience relative to the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance from exposure to adverse localized environments. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the reduced electrical insulation resistance aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Program Description

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is an existing performance monitoring program that will manage the effects of reduced insulation resistance of non-EQ cable and connection electrical insulation in instrumentation circuits with sensitive, high voltage, low-level current signals. The program applies to the in scope portions of the Neutron Monitoring System and the Radiation Monitoring System, that are located in areas with potential adverse environments and are not managed by the Environmental Qualification of Electric Equipment (B.3.1.3) program. The adverse localized environments are caused by temperature, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance causing increases in leakage currents. Other instrument circuits in the Neutron Monitoring System and Radiation Monitoring System are not in scope of this aging management program either because they do not perform a license renewal intended function; they are not sensitive high voltage, low-level signal circuits; or they are managed by the Environmental Qualification of Electric Equipment (B.3.1.3) program.

Calibration or surveillance testing will be performed for the in scope circuits when the cables are included as part of the calibration or surveillance circuit. The calibration and surveillance results will be periodically reviewed to provide an indication of the existence of aging effects based on acceptance criteria for instrumentation circuit performance. Review of results obtained during normal calibration and surveillance may detect severe aging degradation prior to the loss of the cable and connection intended function. A proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed for the in scope circuits when the cables are not included as part of the calibration or surveillance or as an alternative to the review of calibration or surveillance results. Individual calibration and cable test results that do not meet acceptance criteria are evaluated in the corrective action program.

Periodic review of calibration or surveillance results will first be performed prior to the second period of extended operation and at least once every 10 years during the second period of extended operation. If cable tests are credited for program implementation, cable test frequency will be based on engineering evaluation and will be performed at least once every 10 years.

NUREG-2191 Consistency

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program will be consistent with the ten elements of aging management program XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental

Qualification Requirements Used in Instrumentation Circuits," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements.

1. Add the following radiation monitors to the scope of this program
   a. Main steam line radiation monitors
   b. Reactor building ventilation exhaust radiation monitors
   c. Control room fresh air supply radiation monitors
   d. Control room emergency ventilation supply radiation monitors
   e. Main stack radiation monitors

Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Acceptance Criteria (Element 6).

2. 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. Perform the first periodic review for second license renewal prior to the second period of extended operation and at least every 10 years thereafter. **Program Elements Affected: Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5).**

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed for the non-EQ electrical insulation for electrical cables and connections used in instrumentation circuits aging management activities in support of preparing the license renewal application for second license renewal. The electrical insulation included in this program effectiveness review is managed by the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program as described in UFSAR Section Q.1.17. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program, to identify and correct age-related degradation of electrical cable and connection insulation, is being effectively implemented in the first license renewal period of extended operation. The program

effectiveness review was comprised of a review of calibration results and issues in the corrective action program, searching for identified age degradation of electrical insulation for the in scope LPRM and WRNM cables and connections. Calibration results and issues in the corrective action program, from 2003 through 2016 included instrument loops requiring calibration due to instrument drift, detectors failing and being replaced at end of life, active component obsolescence replacements, and cable testing using time domain reflectometry and I/V curves as part of troubleshooting to assure insulation integrity. These reviews did not identify degradation of electrical insulation for in scope LPRM and WRNM cables and connections. The performance of calibration tests and evaluation of issues in the corrective action program have resulted in the effective implementation of this aging management program. The program effectiveness review also determined that the program is being implemented in accordance with UFSAR Section Q.1.17.

This operating experience provides objective evidence that the results demonstrate the maintenance practices and the corrective action program effectively monitor electrical insulation in LPRM and WRNM circuits to assure that these circuits will be able to continue to perform their intended functions and that appropriate aging management will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that this aging management program has effectively managed potential reduction in electrical insulation resistance for in scope instrument circuits with sensitive high voltage, low-level current signals.

2. In January 2013, it was identified that one channel of control room emergency ventilation radiation monitors had failed downscale. The failure was attributed to failure of the power supply for the temperature indicating switch. As part of the evaluation of the failure, it was identified that the control room emergency ventilation radiation monitors and associate equipment were obsolete. Plant sponsorship was obtained to upgrade the control room emergency ventilation radiation monitoring equipment to sustain future system performance. An engineering change package implemented replacement of the obsolete detectors, pre-amplifiers, local cabinet ratemeters, control room ratemeters, and the detector integral cable to the pre-amplifier.

This operating experience, although not attributed to cable or connection electrical insulation aging, provides objective evidence that existing maintenance practices and the corrective action program effectively identify and correct observed instrument deficiencies.

3. In July 2004, during the performance of main steam line radiation monitor calibration, a high radiation alarm was received several times. It was determined, as a result of moving cables and connections in a junction box, that the triaxial cable connection assembly and splices located in the junction box, used for one of the main steam line radiation monitor detectors, failed. An identical replacement cable was not available. An alternate cable assembly was identified and evaluated as an equivalent cable for this application. New cables and connections were installed.

This operating experience, although not directly attributed to cable or connection electrical insulation aging, provides objective evidence that existing maintenance calibration practices and the corrective action program effectively identify and correct observed instrument deficiencies.

The operating experience relative to the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program did not identify an adverse trend in performance. The calibration and periodic review methods being implemented by the program, including any subsequent actions have been proven effective in detecting aging effects including reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will provide reasonable assurance that the reduced electrical insulation resistance aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), medium voltage power cables (operating voltage; 2 kV to 35 kV), exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance of the cable’s insulation system due to wetting or submergence, such as dielectric loss (dissipation factor or power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state of the art at the time the test is performed. The first tests will be completed prior to the second period of extended operation. The cables will be tested at least once every six years thereafter. More frequent testing may occur based on test results and operating experience.

Submarine or other cables designed for continuous wetting or submergence are also included in this program as a one-time test with additional periodic tests and inspections determined by one-time inspection results and industry and plant-specific operating experience.

Periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the inspections will occur either at least once per year or at least once every five years for manholes with level monitoring, alarms, and subsequent pump-out prior to wetting or submergence of cables. The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.

Cable testing and manhole inspection results that do not meet the acceptance criteria are evaluated in the corrective action program.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191 recommends, as a preventive measure, periodic actions to prevent inaccessible medium voltage power cables from being exposed to significant moisture, such as identifying and inspecting conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed. Inspections for water accumulation and manhole condition are to occur at least once annually. Additionally, inspections for water accumulation are also to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

At PBAPS:

- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected at least once every five years, as supported by plant operating experience.
- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected following event driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding, when level monitoring indicates water is accumulating.

Program Element Affected: Preventive Actions (Element 2)

Justification for Exception

As described in NUREG-2191, AMP XI.E3A guidelines, the purpose of this element is to prevent exposing inaccessible non-EQ medium voltage power cables to significant moisture.

In January and February of 2010, three separate issue reports were issued in the corrective action program at Peach Bottom, identifying deficiencies in actions taken to address potential degradation of cable insulation subject to significant moisture and the potential accumulation of water and physical condition of the associated manholes. A strategy was developed to modify selected manholes to provide permanent monitoring instrumentation. The instrumentation provides an alarm that identifies the manhole is accumulating water and needs to be dewatered. SmartCover level indication was installed, including level sensor, transmitter, power pack, and an antenna. Level indication and alarms are sent via a wireless digital radio signal to a website

where data is retrieved. Level alarm setpoints are controlled by the cable program manager and are adjusted based on rate of water accumulation to pump out accumulating water prior to wetting or submerging cables. Alarms are automatically sent to designated computers for notification. Alarms include notification of pending power pack end of life. Loss of instrument capability for reason other than power, i.e., communication, is also alarmed. Alarm conditions are monitored by shift operators.

As experience was gained with the level monitoring, it was determined that there was not a generic solution to minimizing inaccessible medium voltage power cable exposure to significant moisture. There are several manholes for which water accumulation is not occurring. For some manholes, water accumulation can be managed, to prevent cables from being exposed to significant moisture, by manual pumping following level alarms. Other manholes required configuration modifications such as raising cables above the manhole floor or rerouting of cable to different conduits that don't have water infiltration. A few manholes required the installation of automatic pumps. There are plans for more improvements for frequently alarming manholes. Prioritization for implementing permanent configurations is set by frequency of level alarms and the significance of cables.

With the installation of this level alarm system and timely response to level alarms, there is no need to perform annual inspections for manholes with documented history of preventing cable submergence. Therefore, manholes with level transmitters and operating experience that demonstrate that the original or improved manhole configuration, existing level monitoring and alarms, and timeliness of subsequent pump out are preventing water accumulation from wetting or submerging cables, manhole visual inspections will be performed at least once every five years. Additionally, the level transmitters' continuous monitoring and alarms preclude the need for event driven inspections. The ability to continuously monitor manhole water accumulation and implement manual or automatic pump out prior to wetting or submergence of cables justifies not performing visual inspections at least once a year or in the event of severe weather. If operating experience indicates increasing water accumulation rates as indicated by more frequent level alarms or cables are found wetted or submerged when performing manual pump outs, the issue is entered into the corrective action program. Corrective actions consider, as appropriate, interim compensatory actions and increasing the frequency of visual inspections until there is sustained, supporting operating experience to support resuming an every five-year inspection frequency.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Add periodic cable testing for additional circuits. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3)**

2. Perform cable testing of the circuits in the scope of the program at a frequency of at least once every six years. **Program Element Affected:**

Detection of Aging Effects (Element 4)

3. Add periodic condition monitoring, as a preventive action, for manholes. **Program Elements Affected: Scope of Program (Element 1), Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3)**

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed on the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program as described in UFSAR Section Q.3.5, in support of preparing the license renewal application for second license renewal. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of electrical insulation of inaccessible, medium voltage power cables, is being effectively implemented in the first license renewal period of extended operation. These activities included testing of 12 medium voltage power cables to provide an indication of the condition of the conductor insulation, documentation of findings, and follow-up actions in the corrective action program.

The program effectiveness review was comprised of a review of the test results for the 12 cables in the scope of the program, related issues in the corrective action program, searching for identified age-related degradation of electrical insulation for inaccessible medium voltage power cables. Issues in the corrective action program, from 2007 through 2016, were reviewed.

For 10 of the circuits included in the scope of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, that were tested prior to the first period of extended operation, test results indicated the electrical insulation was in “good” condition, with no recommended follow-up actions. For the other two circuits tested, the 4 kV feeder from the 3EA transformer to the 4 kV metal enclosed bus, and the 13 kV feeder from the #1 auto transformer in the north substation to the 3SU switchgear, some of the test results for individual cables in these two circuits indicated some age degradation was occurring. For the circuit from the 3EA transformer to the 4 kV metal enclosed bus, follow-up testing was performed in 2014. For the circuit from the #1 auto transformer to the 3SU switchgear, follow-up testing was performed in 2015. Remediation activities are in progress.

During this time period, there were other inaccessible cable tests and instances of cable degradation and failure, but these issues were for circuits not in the scope of the first aging management activities for inaccessible power cables.

There were no issues in either the pre-period of extended operation implementation or the current period of extended operation related operating experience items, where an in scope cable was unable to perform its intended function due to age-related degradation. The performance of cable tests and evaluation of issues in the corrective action program have resulted in the effective implementation of this aging management program. The program effectiveness review determined that the program is being implemented in accordance with UFSAR Section Q.3.5.

This operating experience provides objective evidence that the cable tests and the corrective action program effectively monitor electrical insulation for inaccessible medium voltage power cables to assure that these circuits will be able to continue to perform their intended functions and that appropriate aging management will be performed during the second period of extended operation. In addition, this operating experience provides objective evidence that this aging management program has effectively managed potential reduction in electrical insulation resistance for in scope, non-EQ, inaccessible, medium voltage power cables.

2. In 2007, the NRC issued Generic Letter (GL) 2007-01, requesting failure histories and associated information describing cable inspection, testing, and monitoring programs to detect the degradation of inaccessible power cables, for circuits that are safety-related or in scope of maintenance rule. The purpose of the GL was to: inform licensees that the failure of certain power cables can affect the functionality of multiple accident mitigation systems or cause plant transients, inform licensees that the absence of adequate monitoring of cable insulation could result in abrupt failures, and request information about current associated test practices. The GL was entered into the operating experience and corrective action programs. PBAPS specific operating experience was documented in the Exelon corporate response to the generic letter. In reviewing plant-specific operating experience related to inaccessible power cables, PBAPS had experienced some failures of continuously energized, but lightly loaded, medium voltage cross linked polyethylene (XLPE) insulated cables in wet environments. The failures were attributed to water treeing. To mitigate future cable failures in wet environments, designated susceptible medium voltage XLPE insulated cables were replaced with either tree resistant XLPE or ethylene propylene rubber (EPR) cables. Normally de-energized circuits and certain low-risk continuously energized circuits, have retained the XLPE cables. In response to GL 2007-01, PBAPS identified past failures and began improvement actions to address cable condition monitoring. Actions included identification of past inaccessible cable insulation failures, identification of susceptible circuits and associated circuit configuration to prioritize cable condition monitoring actions, implementation of cable tests, performance of proactive cable replacement if cable risk significance and test results so indicated, and proactive preparation, i.e., cable specification and selection and work planning, in the event of an emergent failure. These actions are documented in corrective action program.

In 2009, PBAPS received a Green Non-Cited Violation (NCV) because it had not maintained safety-related power cables, including low voltage cables, in an environment for which they were designed and tested. Specifically, PBAPS did not adequately select and review for suitability of application of materials, a 480 volt AC power cable feeding a safety-related motor control center that was in a submerged environment in manhole 35 for an extended period of time, at least for the previous eight years. The NCV was entered into the corrective action program. In 2010, a corrective action issue was created to: 1) address known adverse cable submergence and degraded cable support conditions in manholes; and 2) implement a strategy for periodic diagnostic testing and trending to monitor cables insulation conditions. The associated corrective actions included:

- Short-term and long-term cable testing schedule
- Review/revision of the cable program's cable operability evaluation based on test results
- Re-routing of cables, to change ambient environments
- Cables replacements, as indicated by cable test results.

The fleet-wide response to PBAPS operating experience established a cable condition monitoring program that implements periodic cable testing and uses the test results to determine if additional testing or corrective action may be required. The actions are included in the corrective action program.

This operating experience provides objective evidence that the corrective action program was used to address the need for improvement in the aging management of inaccessible power cables, under 10 CFR Part 50. This example also demonstrates that the operating experience program is used to implement programmatic improvement in the aging management of inaccessible power cables throughout the Exelon Nuclear fleet. .

3. In 2009 and 2010, issues were raised and entered into the corrective action program to address degraded cable support conditions in manholes and accumulating water subjecting cables to significant moisture. Corrective actions, for manholes included:

- Identify which manholes which can remain dry with just preventive maintenance (PM) activities in place.
- Determine the scope of work and obtain financial sponsorship for final, permanent manhole de-watering capabilities, including automatic dewatering pumps, as necessary.
- Establish the schedule to implement permanent manhole de-watering capabilities.
- Complete repairs or modification to underground structures and drainage systems.
- Implement a permanent dewatering strategy for 33 safety-related manholes and remaining maintenance rule manholes that may include water

detection, automatic pumping, reliance on an inspection PM, or a combination of these options.

- Create PM tasks to inspect and pump out manholes
- Transfer manhole level alarm monitoring to operations.
- Implement engineering change requests to install manhole covers with level transmitters, to correct water intrusion, and to elevate cables off the bottom of manholes.
- Identify frequently alarming manholes and track implementation of additional corrective actions.

The manhole improvement initiative, started in 2010, is nearing its final stages for safety-related and maintenance rule cable manholes at PBAPS. Manhole condition monitoring was provided by installing level monitoring in manhole covers. The water level in the manholes and transmitter trouble alarms for power and communications were monitored via satellite link, with alarm monitoring by operations. Frequently alarming and high-risk manholes were evaluated to determine a resolution so that inaccessible medium voltage power cables were not subjected to significant moisture. Resolutions included repairing manhole covers and associated gaskets, repairing conduit seals, raising cables off the floors of some manholes, rerouting cables to not use inaccessible raceways that were facilitating water intrusion, and adjusting the setpoints for manhole water accumulation level alarms. When these solutions did not succeed in limiting in scope cables to significant moisture, modifications for permanent dewatering pumps were designed and installed.

This operating experience provides objective evidence that manhole improvement initiatives to reduce inaccessible medium voltage power cable exposure to significant moisture are nearing completion. Issues have been entered into the corrective action program where follow-up actions are tracked to completion. Ongoing level monitoring, pump outs, and inspections of manholes are providing reasonable assurance that inaccessible medium voltage power cables are not being exposed to significant moisture. Combined with cable testing, the recent improvement to the manholes will provide reasonable assurance that inaccessible medium voltage power cables will continue to perform their intended function through the second period of extended operation.

Additional operating experience information for manholes containing in scope, inaccessible medium-voltage cables is contained within the operating experience discussions in SLRA Sections B.2.1.40 and B.2.1.41, which describe the inaccessible instrument and control cables and the inaccessible low voltage power cables aging management programs, respectively. These operating experience items include improvement initiatives for manholes and plant initiated cable condition monitoring activities for inaccessible cables.

The operating experience relative to the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods being implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance from exposure to significant moisture. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.40 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

A sample of in scope, inaccessible instrument and control cables, potentially exposed to significant moisture, will be tested in a one-time confirmatory effort. The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance. The tests will be performed prior to the second period of extended operation. The in scope inaccessible instrument and control cables, potentially exposed to significant moisture, will also be visually inspected to identify if observable age degradation of the electrical insulation is occurring. The visual inspection will be performed for cables and connections that are accessible during manhole inspections. The visual inspections will occur at least once every six years co-incident with manhole inspections that are being performed at least once every year or at least once every five years. The first visual inspection of inaccessible instrument and control cables will be completed prior to the second period of extended operation.

There are no current submarine or other cables designed for continuous wetting or submergence in the scope of this program. Future cables of this design would be considered for inclusion in this program.

Periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the manhole inspections will be performed either at least once every year or at least once every five years based on operating experience of individual manhole level monitoring and pump out activities.

Cable testing, visual cable inspection, and manhole inspection results that do not meet the acceptance criteria are evaluated in the corrective action program.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" specified in NUREG-2191 with an exception as described below.

Exceptions to NUREG-2191

1. NUREG-2191 recommends, as a preventive measure periodic actions to prevent inaccessible instrument and control cables from being exposed to significant moisture, such as identifying and inspecting conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed. Inspections for water accumulation and manhole condition are to occur at least once annually. Additionally, inspections for water accumulation are also to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

At PBAPS:

- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected at least once every five years, as supported by plant operating experience.

- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected following event driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding, when level monitoring indicates water is accumulating.

Program Element Affected: Preventive Actions (Element 2)

Justification for Exception:

As described in NUREG-2191, AMP XI.E3B guidelines, the purpose of this element is to prevent exposing inaccessible non-EQ instrument and control cables to significant moisture.

In January and February of 2010, three separate issue reports were issued in the corrective action program at Peach Bottom, identifying deficiencies in actions taken to address potential degradation of cable insulation subject to significant moisture and the potential accumulation of water and physical condition of the associated manholes. A strategy was developed to modify selected manholes to provide permanent monitoring instrumentation. The instrumentation provides an alarm that identifies the manhole is accumulating water and needs to be dewatered. SmartCover level indication was installed, including level sensor, transmitter, power pack, and an antenna. Level indication and alarms are sent via a wireless digital radio signal to a website

where data is retrieved. Level alarm setpoints are controlled by the cable program manager and are adjusted based on rate of water accumulation to pump out accumulating water prior to wetting or submerging cables. Alarms are automatically sent to designated computers for notification. Alarms include notification of pending power pack end of life. Loss of instrument capability for reason other than power, i.e., communication, is also alarmed. Alarm conditions are monitored by shift operators.

As experience was gained with the level monitoring, it was determined that there was not a generic solution to minimizing inaccessible instrument and control cable exposure to significant moisture. There are several manholes for which water accumulation is not occurring. For some manholes, water accumulation can be managed, to prevent cables from being exposed to significant moisture, by manual pumping following level alarms. Other manholes required configuration modifications such as raising cables above the manhole floor or rerouting of cable to different conduits that don't have water infiltration. A few manholes required the installation of automatic pumps. There are plans for more improvements for frequently alarming manholes. Prioritization for implementing permanent configurations is set by frequency of level alarms and the significance of cables.

With the installation of this level alarm system and timely response to level alarms, there is no need to perform annual inspections for manholes with documented history of preventing cable submergence. Therefore, manholes with level transmitters and operating experience that demonstrate that the original or improved manhole configuration, existing level monitoring and alarms, and timeliness of subsequent pump out are preventing water accumulation from wetting or submerging cables, manhole visual inspections will be performed at least once every five years. Additionally, the level transmitters' continuous monitoring and alarms preclude the need for event driven inspections. The ability to continuously monitor manhole water accumulation and implement manual or automatic pump out prior to wetting or submergence of cables justifies not performing visual inspections at least once a year or in the event of severe weather. If operating experience indicates increasing water accumulation rates as indicated by more frequent level alarms or cables are found wetted or submerged when performing manual pump outs, the issue is entered into the corrective action program. Corrective actions consider, as appropriate, interim compensatory actions and increasing the frequency of visual inspections until there is sustained, supporting operating experience to support resuming an every five-year inspection frequency.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2016, during a test of an emergency diesel generator, the main control room stop pushbutton did not stop the diesel engine. Resistance readings identified that a specific conductor in the control circuit was indicating as an open circuit. The time domain reflectometry test identified the open circuit as being in a portion of the circuit located in a manhole. The issue was entered into the corrective action program. Follow-up visual inspection did not identify observable degradation of the cable insulation. There was a spliced section in the cable that was physically located in the space inside a manhole. The spliced cable and associated splices were not installed in compliance with standard wiring specifications. When the splice was removed for repair, there was evidence that water had penetrated the splice and subsequently the cable. The cable splice was replaced and megger testing verified that the open circuit condition was corrected. This issue had no effect on the ability of the diesel generator to perform its safety functions to start in response to a loss of offsite power (LOOP) or LOCA signal, accelerate in the required time, supply power to its emergency bus, carry load, and transfer loads to the offsite source. Surveillance requirements were reviewed and it was determined that they could be met without the function of the shutdown circuit.

The operating experience provides objective evidence that routine surveillance testing identified the degradation of the splice that was not made according to standards. Issues identified through routine surveillance are entered into the corrective active program where causes are identified and appropriate corrective actions are implemented. Ongoing equipment testing identifies deficiencies in instrument and control circuits so that they are corrected.

2. In April 2015, the “level alert” alarm for manhole 90A was received. The level alert was entered into the corrective action program for tracking purposes and initiation of inspection and pump out. Level monitoring capabilities were installed for both compartments of this manhole in 2013 in accordance with manhole improvement initiatives as part of corrective actions to keep inaccessible cables “dry.” This manhole contains safety-related control cables that are in scope for second license renewal. The level transmitter and associated monitoring and alarms were installed to determine the extent of cable wetting or submergence in manholes containing safety-related or maintenance rule cables. The operating experience provided data to determine the best options for remediation of manholes with recurring cable wetting or submergence. For the “A” compartment there were six recurring level alarms during initial operation. For the past four years, there have only been two level alarms for the “A’” compartment, none of which had an associate condition report for wetted cables. The “B” compartment alarm for high level has not occurred since the level monitor was installed. The level monitors have determined that no additional manhole modification is required. The contained cables are not exposed to significant moisture.

This operating experience provides objective evidence that installation of level monitoring for manholes has provided an effective method to monitor the accumulation of water, if occurring, and initiate subsequent pump out, when required. For manholes without recurring cable wetting or submergence, the level monitoring provides an ongoing, real time, assurance that infiltration of water into in scope cable manholes is not occurring. If water accumulation occurs it will be alarmed, the condition will be entered into the corrective action program, and the manhole will be pumped out in a timely manner and evaluated for physical improvements if the frequency of high level alarms so indicates.

Additional operating experience information for manholes containing in scope, inaccessible instrument and control cables is contained within the operating experience discussions in SLRA Sections B.2.1.39 and B.2.1.41, which describe inaccessible medium voltage power cables and the inaccessible low voltage power cables aging management programs, respectively. These operating experience items include improvement initiatives for manholes and plant initiated cable condition monitoring activities for inaccessible cables.

The operating experience relative to the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods being implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be performed to identify the areas that need improvement to maintain the effective performance of the program. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.41 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low voltage power cables (operating voltage less than 2 kV), exposed to significant moisture. For this program, significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.

In scope, inaccessible low voltage power cables, potentially exposed to significant moisture, will be tested in a one-time confirmatory effort. The cables within the scope of this program will be tested using one or more proven tests for detecting reduced insulation resistance. The tests will be performed prior to the second period of extended operation. The in scope inaccessible low voltage power cables, potentially exposed to significant moisture, will also be visually inspected to identify if observable age degradation of the electrical insulation is occurring. The visual inspection will be performed for cables and connections that are accessible during manhole inspections. The visual inspections will occur at least once every six years co-incident with manhole inspections that are being performed at least once every year or at least once every five years. The first visual inspection of inaccessible low voltage power cables will be completed prior to the second period of extended operation.

There are no current submarine or other cables designed for continuous wetting or submergence in the scope of this program. Future cables of this design would be considered for inclusion in this program.

Periodic actions are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and subsequent draining of accumulated water or other corrective actions, as needed. Prior to the second period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. The first inspections will be completed prior to the second period of extended operation. During the second period of extended operation, the manhole inspections will be performed either at least once every year or at least once every five years based on operating experience of individual manhole level monitoring and pump out activities.

Cable testing and manhole inspection results that do not meet the acceptance criteria are evaluated in the corrective action program.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" specified in NUREG-2191 with an exception as described below.

Exceptions to NUREG-2191

1. NUREG-2191 recommends, as a preventive measure periodic actions to prevent inaccessible low voltage power cables from being exposed to significant moisture, such as identifying and inspecting conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed. Inspections for water accumulation and manhole condition are to occur at least once annually. Additionally, inspections for water accumulation are also to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

At PBAPS:

- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected at least once every five years, as supported by plant operating experience.

- Manholes with level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cables, will be inspected following event driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding, when level monitoring indicates water is accumulating.

Program Element Affected: Preventive Actions (Element 2)

Justification for Exception:

As described in NUREG-2191, AMP XI.E3C guidelines, the purpose of this element is to prevent exposing inaccessible non-EQ low voltage power cables to significant moisture.

In January and February of 2010, three separate issue reports were issued in the corrective action program at Peach Bottom, identifying deficiencies in actions taken to address potential degradation of cable insulation subject to significant moisture and the potential accumulation of water and physical condition of the associated manholes. A strategy was developed to modify selected manholes to provide permanent monitoring instrumentation. The instrumentation provides an alarm that identifies the manhole is accumulating water and needs to be dewatered. SmartCover level indication was installed, including level sensor, transmitter, power pack, and an antenna. Level indication and alarms are sent via a wireless digital radio signal to a website

where data is retrieved. Level alarm setpoints are controlled by the cable program manager and are adjusted based on rate of water accumulation to pump out accumulating water prior to wetting or submerging cables. Alarms are automatically sent to designated computers for notification. Alarms include notification of pending power pack end of life. Loss of instrument capability for reason other than power, i.e., communication, is also alarmed. Alarm conditions are monitored by shift operators.

As experience was gained with the level monitoring, it was determined that there was not a generic solution to minimizing inaccessible low voltage cable exposure to significant moisture. There are several manholes for which water accumulation is not occurring. For some manholes, water accumulation can be managed, to prevent cables from being exposed to significant moisture, by manual pumping following level alarms. Other manholes required configuration modifications such as raising cables above the manhole floor or rerouting of cable to different conduits that don't have water infiltration. A few manholes required the installation of automatic pumps. There are plans for more improvements for frequently alarming manholes. Prioritization for implementing permanent configurations is set by frequency of level alarms and the significance of cables.

With the installation of this level alarm system and timely response to level alarms, there is no need to perform annual inspections for manholes with documented history of preventing cable submergence. Therefore, manholes with level transmitters and operating experience that demonstrate that the original or improved manhole configuration, existing level monitoring and alarms, and timeliness of subsequent pump out are preventing water accumulation from wetting or submerging cables, manhole visual inspections will be performed at least once every five years. Additionally, the level transmitters' continuous monitoring and alarms preclude the need for event driven inspections. The ability to continuously monitor manhole water accumulation and implement manual or automatic pump out prior to wetting or submergence of cables justifies not performing visual inspections at least once a year or in the event of severe weather. If operating experience indicates increasing water accumulation rates as indicated by more frequent level alarms or cables are found wetted or submerged when performing manual pump outs, the issue is entered into the corrective action program. Corrective actions consider, as appropriate, interim compensatory actions and increasing the frequency of visual inspections until there is sustained, supporting operating experience to support resuming an every five-year inspection frequency.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program. Although there are no license renewal commitments for testing of inaccessible low voltage power cable insulation, or inspection of associated manholes, some of these activities have been performed for in scope as well as other low voltage inaccessible cables over the past several years as part of the Exelon fleet-wide cable condition monitoring program. Since 2015, 11 of the cables identified for this program have already been tested. Test results indicate that the cable insulation is “Satisfactory,” which means little aging degradation of inaccessible low voltage power cable exposed to significant moisture is occurring. Results are documented in completed work order permanent records. Another three circuits in the sample identified for this program are scheduled for testing. The remaining circuits are yet to be scheduled.

This operating experience provides objective evidence that the electrical insulation for inaccessible low voltage power cables at Peach Bottom is not susceptible to electrical insulation degradation due to exposure to significant moisture, which will be verified by one-time confirmatory testing prior to the second period of extended operation. These confirmatory tests will provide reasonable assurance, that the electrical insulation for inaccessible low voltage power cables will continue to perform their intended function through the second period of extended operation.

2. In 2008, there was a failure of inaccessible low voltage power cables that fed a 480 V motor control center in the main stack structure. The cable failure was entered into the corrective action program. The feeder circuit cables were 480 V, inaccessible power cables subject to significant moisture. Temporary, compensatory actions for manual radiation readings were taken, and a temporary power supply was provided until permanent repairs were made. The duct bank through which the cable was routed, failed at two different transition locations between the rigid poured concrete duct bank and compacted backfill because the compacted soil no longer provided adequate support. Cable testing via measurement of insulation resistance was performed during troubleshooting. Through cable testing and duct inspection, it was determined there was no electrical insulation aging degradation for this cable. Work completed for the new feeder cable is documented in the permanent work record completion remarks. The duct bank and cable failure are a byproduct of the less than robust design for the capacity of the roadway over the duct bank. The cause evaluation for the structural deficiencies and corrective actions are documented in the corrective action program. To address the structural issue, a design change was implemented to improve the load capacity of the duct bank and the roadway surface was repaired and sealed.

This operating experience is the only failure of an inaccessible, low voltage power cable found in a search of the corrective action program issues back to 2003. Since this is the only issue of failure of a low voltage power circuit, and it is not associated with age-related degradation of electrical insulation, this operating experience provides objective evidence that the electrical insulation for inaccessible low voltage power cables is not susceptible to insulation degradation caused by significant moisture. Additionally, the use of insulation resistance testing for troubleshooting is aligned with commonly implemented test methodologies and with the test methodology proposed within this program. Furthermore, with no past failure and an accepted test methodology, this operating experience provides further support for implementation of this program via confirmatory testing, on a one-time basis, prior to the second period of extended operation. Combined with the periodic manhole and accessible cable inspections, the one-time confirmatory cable insulation testing will provide reasonable assurance that the inaccessible low voltage cables will continue to perform their intended functions through the second period of extended operation.

3. In 2011, manhole 041 was included in the population of manholes to have a level transmitter installed for managing water accumulation in manholes containing risk significant cables. Alarms for high water level were received on an ongoing basis for manhole 041. These occurrences were documented in the corrective action program. As part of the inspections during pump outs it was discovered that the cables in manhole 041 were not supported and were laying on the floor of the manhole. Corrective action was implemented to raise the cables above the floor of the manhole, reducing the number of times that the manhole required pump out and minimizing the cables' exposure to significant moisture. Even though the low voltage power cable to the Unit 2 startup switchgear and this associated manhole were not part of a commitment for first license renewal, this action was implemented as part of corrective actions to reduce inaccessible cable exposure to significant moisture.

This operating experience provides objective evidence that the manholes for inaccessible low voltage power cables are routinely monitored to reduce cable exposure to significant moisture. Ongoing management of water accumulation in manholes will provide reasonable assurance that the electrical insulation for inaccessible low voltage power cables will continue to perform their intended function through the second period of extended operation.

4. In August 2009, during bus cleaning for a 480 V motor control center that is not in scope for license renewal, a megger test was performed as part of post maintenance testing. The "B" phase cable insulation resistance was found to be below acceptance criteria. The results of the megger tests were entered into the corrective action program and evaluated. The evaluation documented that previous post maintenance testing identified that the "B" phase cable insulation was determined by megger test to be lower than phases "A" and "C"; however, the measured value was above acceptance criteria. The technical evaluation identified that the "B" phase cable insulation was slowly deteriorating and should be replaced; however, replacement is not an immediate concern for this circuit providing power to a water treatment plant motor control center.

This operating experience demonstrates the technical acceptability of megger testing to assess cable insulation condition, specifically because there were no occurrences of degraded conditions identified during recent megger tests for routine cable condition monitoring.

Additional operating experience information for manholes containing in scope, inaccessible low voltage power cables is contained within the operating experience discussions in SLRA Sections B.2.1.39 and B.2.1.40, which describe the inaccessible medium voltage power cables and the inaccessible instrument and control cables aging management programs, respectively. These operating experience items include improvement initiatives for manholes and plant initiated cable condition monitoring activities for inaccessible cables.

The operating experience relative to the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods to be implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement will be provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be performed to identify the areas that need improvement to maintain the effective performance of the program. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will provide reasonable assurance that the identified effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.42 Metal Enclosed Bus

Program Description

The Metal Enclosed Bus aging management program is a new condition monitoring program, that uses sampling and will manage the identified aging effects of in scope metal enclosed bus. The internal portions of the accessible bus enclosure assemblies will be visually inspected for age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation will be visually inspected for signs of reduced insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination which may indicate overheating or aging degradation. The internal bus insulating supports will be visually inspected for structural integrity and signs of cracks. External surfaces in an air-outdoor environment will be visually inspected for loss of material due to general, pitting, and crevice corrosion. There are no gaskets, boots, and sealants as part of the external portions, including access panels, for the in scope metal enclosed buses; therefore, there will be no aging management activities for elastomers in this aging management program.

A sample of accessible bolted connections will be inspected for increased resistance of connection by either performing thermography or measuring the connection resistance using a micro-ohmmeter. In addition to thermography or resistance measurement, bolted connections not covered with heat shrink tape or boots are visually inspected for increased resistance of connection (e.g., loose or corroded bolted connections and hardware including cracked or split washers). The sample will be of 20 percent of the accessible metal enclosed bus bolted connection population with a maximum sample size of 25.

Metal enclosed bus inspection and testing acceptance criteria are included in implementing procedures. Metal enclosed bus inspections and tests that do not meet the acceptance criteria are evaluated in the corrective action program.

This new program will be implemented prior to the second period of extended operation. The inspections and resistance measurements will be performed prior to the second period of extended operation and at least once every 10 years during the second period of extended operation.

NUREG-2191 Consistency

The Metal Enclosed Bus aging management program will be consistent with the ten elements of aging management program XI.E4, "Metal Enclosed Bus" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Metal Enclosed Bus program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In April 2012, during the performance of de-termination of a startup transformer for Doble testing of the startup transformer, the work crew observed a crack in the bus insulation of the connecting metal enclosed bus. The observation was entered into the corrective action program for evaluation. It was determined that the bus insulation needed to be replaced to prevent further degradation, prior to returning the transformer to service. The repair was performed when connections were re-terminated following testing of the transformer.

This operating experience provides objective evidence that when maintenance personnel identify degraded conditions, the conditions are entered into the corrective action program for evaluation and repair, ensuring the buses' capability to perform their intended function.

2. In November 2009, INPO Significant Event Report 5-09 was issued for a 6.9 kV non-segregated bus failure at another plant. The review of this industry operating experience was entered into the corrective action program for evaluation of applicability to PBAPS. PBAPS has not experienced similar issues with their metal enclosed bus. In response to this industry operating experience, activities were initiated to incorporate the lessons learned from this event, specifically to perform connection resistance measurement using a Ductor instrument, connection torque checks; connection disassembly, cleaning and reassembly to specified torques values; and evaluation of results. The initial evaluation and subsequent actions were tracked in the corrective action program. The results of the connection tests and inspections found the PBAPS metal enclosed bus connections in good condition. The results are documented in the completed work order. These actions provide objective evidence that industry operating experience is being used to improve condition monitoring of the metal enclosed bus and prevent events that have occurred at other plants.

This operating experience, specifically the results of the inspection, provides objective evidence supporting industry inspection experience results that metal enclosed bus with copper bus bars are less susceptible to connection loosening from repetitive thermal cycling from connected loads.

3. In October 2009, INPO ICES industry operating experience was issued for a safety-related bus duct ground due to formation of condensation inside the bus duct at another plant. An air conditioning duct blowing directly on a safety-related bus duct caused condensation to form inside the bus duct resulting in a phase to ground fault with the bus out of service for maintenance. This operating experience identified the potential for faults due to condensation inside the bus duct enclosure causing corrosion. This industry operating experience was entered into the corrective action program for evaluation of

applicability to PBAPS. No similar occurrences were noted at PBAPS. Procedures for metal enclosed bus inspections were updated to include looking for locations where ventilation impinges on the bus and noting any signs of degradation caused by condensation or corrosion.

These actions provide objective evidence that industry operating experience is being used to improve condition monitoring of the metal enclosed bus and prevent events that have occurred at other plants.

The operating experience relative to the Metal Enclosed Bus program did not identify an adverse trend in performance. The inspection methods being implemented at the station have been proven effective in detecting aging effects including increased electrical resistance of connection, loss of material, and reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Metal Enclosed Bus program will be performed to identify the areas that need improvement to maintain effective performance of the program. The activities are informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Metal Enclosed Bus aging management program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Metal Enclosed Bus aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.1.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program. The program will implement one-time testing of a representative sample of non-EQ electrical cable connections to ensure that either increased resistance of connection is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. This one-time program will provide additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective. This one-time program will also confirm that there are no aging effects requiring management during the period of extended operation. A representative sample of non-EQ electrical cable connections will be selected for one-time testing considering voltage level (medium and low voltage), circuit loading (high loading), connection type, and location (high temperature, high humidity, and vibration). The sample tested will be 20 percent of each connector type with a maximum sample size of 25 connections.

The specific type of test performed will be a proven test method for detecting increased resistance of connections, such as thermography, contact resistance measurement, or another appropriate test without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc. The acceptance criteria are specific for each type of test and the specific type of cable connections tested. Temperature measured by thermography will be evaluated against baselines, if available, or similarly configured components. Connections which cannot be adequately assessed by thermography are assessed by contact resistance measurement or another appropriate test. The justification and technical basis for not performing subsequent periodic testing is documented. Results that do not meet the acceptance criteria are addressed in the corrective action program. The program does not implement visual inspections of cable connection insulation materials as an alternative to thermography.

This new program will be implemented prior to the second period of extended operation. The sample tests and evaluation of results will be completed prior to the second period of extended operation.

NUREG-2191 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In February 2010, during routine thermography, a Unit 3 480 V breaker to fuel pool cooling water pump motor was observed to have an elevated temperature on the "L1" connection. As documented in the corrective action program, it was recommended that the connection be tightened. Monitoring of the connection was performed on an increased frequency until the repair was performed. Post-maintenance thermography connection temperatures were acceptable; no further action was warranted.

These items provide objective evidence that the current maintenance practices are adequate to effectively identify and correct connection issues, prior to impact to equipment operations.

2. In June 2013, elevated temperatures were found during routine thermography on the incoming "L2" line side breaker connection to a Unit 2 reactor building area ventilation supply fan. Connection temperatures were trended at an increased frequency until maintenance activities were performed. Troubleshooting identified that the “L2” wire was tight, but the compression of the wire was offset in the breaker lug. The wire was straightened in the saddle and torqued. Subsequent thermography following maintenance activities confirmed a satisfactory reduction in temperature.

This item provides objective evidence that the current maintenance practices are adequate to effectively identify items for correction, perform interim actions, and monitor until a final repair can be implemented.

3. In January 2015, elevated temperatures were found during routine thermography on the incoming "L2" line side breaker connection to a radwaste building area ventilation exhaust fan. Increased frequency thermography was performed to monitor the connection until incoming lead was repaired. During investigation of the connections, leads were tightened. Post-maintenance thermography connection temperatures were acceptable; no further action was warranted.

This item provides objective evidence that the current maintenance practices are adequate to effectively identify and correct connection issues, prior to impact to equipment operations.

The operating experience relative to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The inspection methods implemented by the program have been proven effective in detecting aging effects including increased electrical resistance of connection. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the increased electrical resistance of connection aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.2.2 Plant-Specific Aging Management Programs

This section provides summaries of the plant-specific programs credited for managing the effects of aging.

B.2.2.1 Wooden Pole

Program Description

The Wooden Pole aging management program is an existing condition monitoring program that manages aging effects associated with the wooden pole adjacent to the Susquehanna Substation that provides the structural support for the conductors connecting the substation to the submarine cable for the alternate AC power for PBAPS's station blackout coping period. There are no preventive or mitigative actions associated with this program. The program manages loss of material and change in material properties by conducting periodic inspections in accordance with corporate specifications of the wooden pole within the scope of the program. Periodic inspections are conducted on a 10-year frequency. Inspection activities consist of visual inspections, sounding, boring, and excavation, as required, to ensure an adequate examination. Acceptance criteria outlined in the corporate specifications ensure appropriate corrective actions are taken based on observed conditions. If an inspection identifies a degraded condition associated with the wooden pole, the corrective action program is utilized to facilitate repair or replacement activities.

Aging Management Program Elements

The results of an evaluation of each element against the 10 elements described in Appendix A of NUREG-2192, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, are provided below.

Scope of Program – Element 1

The plant-specific Wooden Pole aging management program inspects the in scope wooden pole that is adjacent to the Susquehanna Substation. The wooden pole provides structural support for the conductors connecting the substation to the submarine cable for the alternate AC power for PBAPS's station blackout coping period.

Preventive Actions – Element 2

This aging management program is a condition monitoring activity. There are no preventative or mitigative actions associated with this aging management program.

Parameters Monitored or Inspected – Element 3

The wooden pole in the scope of this program is inspected for loss of material due to animal, insect, and moisture damage and for change in material properties due to moisture damage using a standard wooden pole inspection specification. Parameters inspected typically evaluate shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay, split tops. Aging management activities consist of visual inspections, sounding, and, if required, boring and excavation activities. The parameters monitored or inspected are capable of detecting the effects of aging that may impact the intended function of providing structural support to electrical conductors.

Detection of Aging Effects – Element 4

The Wooden Pole aging management program detects aging effects prior to the loss of the wooden pole intended function to provide structural support to in scope electrical conductors. This aging management program is based on performing Wooden Pole inspections in accordance with standard specifications.

Parameters are monitored via visual inspections, sounding and, if required, boring and excavating activities. Visual inspections can detect external damage due to animals, insects, lightning, wind, and moisture. Visual inspection does not detect decay underground or internal to the pole. Sounding can detect internal decay and voiding. Boring can detect and quantifying internal decay, allow for analysis of preservative penetration and retention, and allow for shell thickness measurements to be taken for evaluating strength reduction. Excavation allows for inspection below grade at areas most susceptible to moisture damage and allows for below grade boring activities. The parameters typically monitored include shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay and split tops. The inspections identify loss of material and change in material properties. The inspections of the wooden pole are performed every 10 years by a qualified inspector. The Wooden Pole program manages the aging effects of the wooden pole to ensure its availability to perform its intended function throughout the second period of extended operation. This aging management program does not take credit for redundancy, diversity or defense in depth. This aging management program employs industry standardized practices to perform condition monitoring and subsequent corrective actions and is not based detection of failure.

The typical life for a wooden pole without maintenance, based on industry experience, is 30 to 40 years. The reject rates of wood utility poles that are included in a comprehensive maintenance program project a life greater than 100 years. Pennsylvania code inspection and maintenance standards state that distribution poles shall be inspected at least as often as every 10-12 years except for new southern yellow pines creosoted utility poles which shall be inspected within 25 years, then within 12 years annually after the initial inspection. There is no national standard for inspecting poles. However, industry experience over several decades indicates that a 10-year inspection interval is adequate.

The Wooden Pole aging management program is a condition monitoring program. Sampling is not part of this program. The program is not a performance monitoring program, and is not a prevention or mitigation program.

Monitoring and Trending – Element 5

Condition monitoring for loss of material and change in material properties is provided in the standard specification for inspection of wooden poles. The wooden pole is inspected at 10-year intervals. Monitoring under this program involves a combination of visual, sounding, boring, and excavation activities to determine the condition of the pole. Occurrences of shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay, split tops, which may limit the life of the pole or which require immediate attention in the interest of safety will be recorded, and reported using the corrective action program. These periodic actions are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible. Trending actions are not included as part of this program.

The inspections are performed by qualified wooden pole inspectors. This approach implements the best practices of electrical distribution companies experienced in monitoring and repairing wooden poles. This program's results are evaluated against acceptance criteria that ensure the intended function of the pole is maintained until the next scheduled inspection or required repairs or replacement is performed in a timely manner based upon associated procedural guidance. This program therefore does not include a projection of degradation to the next scheduled inspection. Additionally, sampling is not part of this aging management program.

Acceptance Criteria – Element 6

The acceptance criteria are provided in the specification for inspection of wooden poles. An approved wooden pole maintenance contractor experienced in the inspection, treatment, and reinforcement of wooden poles performs the pole inspection. The inspector, through a combination of visual, sounding, boring, and excavation activities, determines the condition of the pole. Some inspection results will be qualitative; some inspection results will be quantitative, representative of the monitoring that is performed for the wooden pole. This program does not project observed degradation to the end of the second period of extended operation. This program is not a one-time inspection; it is implemented on a periodic basis.

This approach implements the best practices of electrical distribution companies experienced in monitoring and repairing wooden poles. The results of the inspection determine if the wooden pole is acceptable as is or in need of repair or replacement, assuring that the wooden pole will continue to perform its intended function until the next periodic inspection. This program's acceptance criteria are not directly related to nor directly taken from the PBAPS current licensing basis, codes and standards endorsed by NRC regulations, nor NRC-endorsed technical or topical reports.

Corrective Actions – Element 7

The Quality Assurance Program implements the requirements of 10 CFR 50,

Appendix B and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR, in accordance with Exelon's Quality Assurance Topical Report and Corrective Action Program. For additional information, see PBAPS SLRA Appendix B, Section B.1.3.

If an inspection identifies a degraded condition, corrective actions (e.g., treatment, reinforcement or replacement) are taken to restore the structural integrity of a degraded pole. The program will be enhanced to initiate a condition report within the corrective action program to document and evaluate the unacceptable conditions in accordance with plant administrative procedures, including identification of causes and extent of condition.

Inspections are performed by a qualified wooden pole inspector in accordance with established standards. The results of the inspection determine if the wooden pole is acceptable as is or in need of repair or replacement. This process ensures that the wooden pole intended function to provide structural support to electrical conductors will be maintained consistent with the current licensing basis through the second period of extended operation.

Confirmation Process – Element 8

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR, in accordance with Exelon's Quality Assurance Topical Report and Corrective Action Program. For additional information, see PBAPS SLRA Appendix B, Section B.1.3.

When corrective actions are necessary, there are follow-up activities to confirm that the corrective actions have been completed and that the corrective actions have been effective. The Wooden Pole program does not rely on NRC-endorsed technical or topical reports.

Administrative Controls – Element 9

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR, in accordance with Exelon's Quality Assurance Topical Report and

Corrective Action Program. For additional information, see PBAPS SLRA Appendix B, Section B.1.3.

The Wooden Pole program does not rely on NRC-endorsed technical or topical reports.

Operating Experience – Element 10

The following examples of operating experience provide objective evidence that the Wooden Pole program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the Susquehanna Substation Wooden Pole Inspection Activity described in UFSAR Section Q.2.11. The purpose of the aging management program effectiveness review was to verify that the existing aging management program identifies age-related degradation of in scope components and is being effectively implemented in the first period of extended operation. The aging management program effectiveness review was comprised of a review of maintenance inspection records. The review also included pertinent issues found in the corrective action program from year 2001 to 2016, searching for age-related degradation of components within the scope of the Susquehanna Substation Wooden Pole Inspection Activity.

The review identified that inspections of the Susquehanna Substation Wooden Pole Inspection Activity are being performed in accordance with the extent and schedule described in the license renewal commitment. There were two inspections performed on the wooden pole to date. The first inspection for license renewal was performed in 2003. The license renewal commitment for this activity requires that the inspection be completed by a qualified inspector in accordance with the corporate specification. In 2012, review of the work order activity performed in 2003, identified that the qualification record of the inspector was not recorded and a copy of the completed inspection report was not attached to the work package. As a result, the issue was entered into the corrective action program and the implementing recurring work order was updated to ensure the activity be completed by a qualified inspector and that a copy of the completed inspection report be attached to the work package.

The most recent inspection sounded, bored and partially excavated the pole in 2011. Internal sapwood decay was identified and treated with fumigant. No external, below ground line decay was identified and the effective circumference was the same as original installation. No additional work was determined to be required. The review identified that inspections performed within the program are effective at identifying age-related degradation of in scope components before significant degradation has occurred. Age-related issues were evaluated in accordance with corporate procedural requirements, and corrective actions taken to prevent further degradation resulted in effective implementation of this aging management program. The review concludes that the component within the scope of the Susquehanna Substation Wooden Pole inspection Activity program is being implemented as described in UFSAR Section Q.2.11.

This operating experience provides objective evidence that the current Susquehanna Substation Wooden Pole Inspection Activity program is being effectively implemented to manage aging effects. Continued implementation of the Susquehanna Substation Wooden Pole Inspection Activity and future implementation of the Wooden Pole aging management program will assure that the wooden pole within the scope of the program will continue to perform its intended function during both the first period of extended operation and second period of extended operation.

The Wooden Pole aging management program does not rely on NRC-endorsed technical or topical reports.

The operating experience relative to the Wooden Pole program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material; and change in material properties. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Wooden Pole program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Wooden Pole program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Exceptions

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program element.

1. Document results that do not meet the acceptance criteria in the corrective action program.

Program Element Affected: Corrective Actions (Element 7)

Consistency

The Wooden Pole aging management program will be consistent with the ten elements of an aging management program described in NUREG-2192.

Conclusion

The enhanced Wooden Pole aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.3 NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X programs credited for managing the effects of aging.

B.3.1.1 Fatigue Monitoring

Program Description

The Fatigue Monitoring aging management program is an existing preventive program that manages fatigue damage of reactor pressure vessel (RPV) components, reactor coolant pressure boundary piping components, and other components subject to the reactor coolant, treated water, steam, condensation, diesel exhaust, air-outdoor, and air-indoor uncontrolled environments. Components that are managed by the program are fabricated from carbon steel, low alloy steel, stainless steel, nickel alloy, and inconel alloy.

The Fatigue Monitoring aging management program is a preventive program that 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 second period of extended operation. The program monitors and tracks the number and severity of thermal and pressure transients for Units 2 and 3 as specified In UFSAR Table 4.2.4, which is referenced in UFSAR Section 4.2.5 and Tech. Spec. Section 5.5.5. No PBAPS ANSI B31.1 and ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to these implicit analyses. No ASME Section III fatigue waiver analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to fatigue waiver analyses. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth; flaw tolerance, or fracture mechanics analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program utilizes the SI:FatiguePro™ software which is a computerized data acquisition, recording, and tracking program. SI:FatiguePro™ is used to determine the overall cumulative number 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 program monitors the environmental effects of reactor coolant on Class 1 components by using the guidance in RG 1.207, applicable fatigue curves in NUREG/CR-6909, Revision 1, and calculated alternating stress values from the existing ASME Code fatigue calculations to determine CUF_{en} values. In addition, High Energy Line Break (HELB) analyses for the Reactor Recirculation System piping use the CUF values as input in determining intermediate break locations. SI:FatiguePro™ performs “stress-based” and “cycle-based” fatigue monitoring.

The cumulative CUF and CUF_{en} values for the components monitored by SI:FatiguePro™ are compared to appropriate allowable limits (e.g., 1.0 for ASME Section III locations, 0.1 for HELB exclusion locations, or 1.0 for CUF_{en} for environmental fatigue locations). When a cumulative CUF or CUF_{en} value exceeds 80 percent of applicable allowable limit, corrective action is taken to review the applicable fatigue analyses and take appropriate actions to prevent exceeding the limit.

This program verifies the continued acceptability of existing fatigue analyses through transient cycle counting and calculation of cumulative CUF and CUF_{en} values to demonstrate that they continue to meet the appropriate limits. The program requires comparison of actual event parameters to the applicable design transient definitions to ensure the actual transient is bounded by the applicable design transient. CUF and CUF_{en} values are computed parameters used to assess the likelihood of fatigue damage. Fatigue crack initiation is assumed to begin in a mechanical or structural component when the CUF and CUF_{en} values reach the value of 1.0. Reactor Recirculation System piping locations with a CUF value less than or equal to 0.1 do not require an intermediate break to be postulated.

NUREG-2191 Consistency

The Fatigue Monitoring aging management program will be consistent with the ten elements of aging management program X.M1, "Fatigue Monitoring" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements:

1. Update the SI:FatiguePro™ software to include the calculation and tracking of Environmentally Assisted Fatigue (EAF) in accordance NUREG/CR-6909, Revision 1. **Program Element Affected: Program Scope (Element 1).**

2. Update applicable fatigue analyses and monitored component locations are updated based on operating experience, plant modifications, inspection findings, changes to transient definitions, and unanticipated newly discovered fatigue loading events. **Program Elements Affected: Program Scope (Element 1) and Monitoring and Trending (Element 5)**

3. Provide procedural direction to require periodic validation of chemistry parameters used to determine Fen factors used in SI:FatiguePro™. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)**

4. Provide procedural direction to add an additional acceptance criterion

associated with HELB exclusion criteria. **Program Element Affected: Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Fatigue Monitoring program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of the Fatigue Management Activities program described in UFSAR Section Q.4.2, in support of preparing the license renewal application for second license renewal. The purpose of the aging management program effectiveness review was to verify that the intent of the existing aging management program, that is to ensure that the applicable fatigue analyses remain within their allowable limits, is being effectively implemented in the first period of extended operation. The information was collected from 2001 through 2016.

The aging management program effectiveness review was comprised of a review of completed work orders associated with implementation of Fatigue Management Activities and pertinent issues in the corrective action program. The aging management program effectiveness review also evaluated plant-specific results against the commitments for the current program as identified in UFSAR Section 4.2.5; Table 4.2.4; UFSAR Appendix C Section C.5.3; UFSAR Appendix H Section H.3.2.2 and H.3.2.3; UFSAR Appendix M Section M.3.2.1; and NUREG-1769.

The review concluded that PBAPS has implemented all Fatigue Management Activities commitments associated with the first license renewal application. In addition, the review concluded that the Fatigue Management Activities is adequately monitoring accumulated fatigue usage and program concerns are being entered into the corrective action program. Specific examples are included as OE examples 2, 3, and 4 below.

In addition, the review concluded that RIS 2008-30 and RIS 2011-14 have been properly evaluated and considered in the Fatigue Management Activities program.

This operating experience provides objective evidence that the Fatigue Management Activities program is being effectively implemented to monitor components for fatigue usage during the first period of extended operation, and continued implementation of the Fatigue Monitoring program will assure that the monitored components will continue to perform their intended functions during the second period of extended operation.

2. In 2010, the Fatigue Management Activities program was enhanced with the installation of the automated SI:FatiguePro™ cycle counting and fatigue usage factor tracking software. SI:FatiguePro™ monitors plant operating parameters, counts fatigue transient stress cycles, and then calculates, trends, and projects cumulative usage factors (CUFs) for bounding component

locations. Some transient cycles are manually entered into SI:FatigueProTM. The software allows the program manager to accurately monitor fatigue usage of critical locations to ensure that accumulative CUFs values will remain less than the associated design allowable criteria through the first period of extended operation. CUF values are evaluated against the procedural acceptance criteria of 80 percent of the design allowable fatigue usage, and if exceeded, the condition is entered into the corrective action program. The following are some of the components that are monitored by SI:FatigueProTM: RPV shell and various RPV nozzles; reactor recirculation piping; RHR piping; torus shell; torus vents; torus penetrations; the core shroud support, and jet pump support.

In 2015, PBAPS updated the SI:FatigueProTM software to also include the calculation and tracking of Environmentally Assisted Fatigue usage (CUF_{en}) at locations recommended by NUREG/CR-6260, Revision 0. Associated Fatigue Management Activities program procedures were updated so that up-to-date calculated CUF_{en} values are monitored, trended, and projected to ensure that they will remain less than the acceptance criteria through the first period of extended operation.

This example provides objective evidence that the Fatigue Management Activities program implementing software and procedures are effectively updated and improved to more effectively monitor cumulative fatigue usage.

3. When accumulated fatigue usage values exceed the 80 percent procedural acceptance criterion, the condition is consistently entered in a corrective action program issue report. The issue reports have generated evaluations of the affected monitored locations to ensure they will not exceed the acceptance criteria for the current 60-year period of extended operation. These evaluations have demonstrated that although a few accumulated fatigue usage values have exceeded the 80 percent criterion, projected fatigue usage values for the 60-year life of the plant will remain less than the limit of 1.0. For example, as of December 31, 2015, the Unit 2 “Closure Bolt” monitored location had a cumulative usage of 0.801 and the Unit 2 “Recirculation Piping and RHR Return Line Tee” monitored location had a cumulative usage of 0.803. Evaluations of these locations concluded that projected fatigue usage for 60 years would remain less than design limit of 1.0.

Revaluation of the “Recirculation Piping and RHR Return Line Tee” location in 2016 documented that the recirculation and RHR piping, including the monitored location, was replaced in 1984 and 1985 for Units 2 and 3 respectively. Therefore, the total number of associated transient cycles for each unit was modified to remove transient cycles that occurred before the piping replacements. This resulted in an adjustment in the cumulative usage value for the “Recirculation Piping and RHR Return Line Tee” monitored location, which no longer exceeds the 80 percent criterion.

As documented in SLRA Section 4.3.1, the projected 80-year cumulative usage values of these two monitored locations also remains less than the design acceptance criteria of 1.0.

As of December 31, 2015, Unit 3 has no monitored locations in which the cumulative usage exceeds the 80 percent criterion.

This example provides objective evidence that the Fatigue Management Activities program effectively monitors plant transients and cumulative usage, utilizes the corrective action program, and results in evaluations to demonstrate that cumulative usage will continue to meet acceptance criteria during the first period of extended operation for each unit.

4. As described in SLRA Section 4.7.3, NUREG-0619 was issued by the NRC per Generic Letter (GL) 81-11 in February 1981 because of observed cracking on the inside surfaces of BWR feedwater nozzles at the blend radius and bore. The causes included: 1) on-off feedwater flow control at low power, 2) high clad thermal stresses, and 3) leakage between the nozzle and the thermal sleeve. In the original BWR designs the thermal sleeve was loosely fit into the nozzle bore. The leakage caused rapid thermal cycling, on the order of a few cycles per second, driven by convective instability in the mixing region. Such cracking was observed in the feedwater nozzles at PBAPS Units 2 and 3 early in each unit's life, before 1980.

In 1980 and 1981, PBAPS Unit 2 and 3 implemented the following three NUREG-0619 recommended modifications to reduce or eliminate the feedwater nozzle rapid thermal cycling fatigue cracking mechanism: (a) installation of improved nozzle triple thermal sleeves with dual piston ring seals, (b) removal of cladding from the nozzle bore and blend radii, and (c) improvement of the low-flow feedwater controllers. The implementation of the modifications and improvements to plant operations at low flow conditions was effective in preventing additional high cycle fatigue cracking in the Unit 2 and 3 feedwater nozzles.

In 2010, the SI:FatiguePro™ cycle counting and fatigue usage factor tracking program was installed at PBAPS. For the feedwater nozzles, SI:FatiguePro™ calculates "stress-based" cumulative usage values due to normal thermal cycling based on system transients (e.g., startup and shutdown) and rapid thermal cycling caused by the leakage between the feedwater nozzle and the thermal sleeve. The fatigue monitoring of the feedwater nozzles along with periodic in-service inspections of the feedwater nozzles, ensures that this aging effect is effectively managed.

This example provides objective evidence that the Fatigue Monitoring program utilizes industry operating experience and continuous improvement to ensure that cumulative usage of the feedwater nozzles will continue to meet acceptance criteria through the second period of extended operation for each unit.

The operating experience relative to the Fatigue Monitoring program did not identify an adverse trend in performance. Periodic assessments of the Fatigue Monitoring program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Fatigue Monitoring program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Fatigue Monitoring program will provide reasonable assurance that the aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.3.1.2 Neutron Fluence Monitoring

Program Description

The Neutron Fluence Monitoring aging management program is an existing condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor vessel internal (RVI) components to ensure that applicable reactor pressure vessel neutron embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits. The program manages loss of fracture toughness due to neutron irradiation embrittlement. The components evaluated by these analyses are the reactor pressure vessel shell, welds and nozzles in the extended beltline region and RVI components subject to reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC approved reports. For fluence monitoring activities that apply to the beltline region of the reactor pressure vessel(s), the calculational methods are performed in a manner that is consistent with RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” March 2001. The methods used to identify materials within the extended beltline region and RVI components are also consistent with NRC-approved methodology in RG 1.190.

The methods and assumptions for determining RPV neutron fluence for the beltline region are consistent RG 1.190. The methods and assumptions used for the original beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of1×10^{17} n/cm^2 (E > 1 MeV) at 70 EFPY , since the extended region does not extend significantly above or below the active fuel region and no additional reactor vessel plate materials (heat numbers) or welds are projected to experience fluence in excess of 1×10^{17} n/cm^2 (E > 1 MeV). The NRC approved GE Discrete Ordinates Transfer (DORT) methodology utilizes representative BWR surveillance capsule measurements to validate calculational fluence analysis.

Recently, the NRC has identified a concern regarding the uncertainty of RPV fluence projections for elevations above the active fuel and that non-conservative fluence projections could potentially result in the identification of a lower upper extended beltline elevation and exclude the metallurgically evaluation of portions of the RPV that would be exposed to 1.0E+17 n/cm^2 or more, prior to the end of the period of extended operation. As a result, a supplemental metallurgical sensitivity evaluation was performed on RPV components located above the upper extended beltline elevation in addition to the fracture mechanics evaluations of RPV components located within the beltline region (as extended). This supplemental metallurgical sensitivity evaluation and justification was performed for both Unit 2 and 3 RPVs and includes all components above the beltline region (as extended) to an elevation that is 52 inches above the projected upper beltline limit. Each component was assessed using the maximum fluence value from that specific unit found within the midplane of the active fuel region. Results of the supplemental metallurgical sensitivity evaluation concluded that these reactor vessel components meet all the established metallurgical acceptance criteria for ART, USE/EMA, circumferential weld inspection relief, axial weld probability, and reflood thermal shock.

The supplemental metallurgical sensitivity evaluation serves as an analysis and justification that provides reasonable confidence that RPV components above the upper extended beltline elevation would meet the established metallurgical acceptance criteria should future industry resolution of the uncertainty concern result in further extension of the upper extended beltline elevation.

For a more detailed description of this supplemental evaluation and justification, see SLRA Section A.4.2.1.3.

The determination of RVI component fast neutron fluence values is not governed by regulatory guidance or requirements. The purpose of determining the fast neutron fluence values of RVI components is to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), crack growth rates, and support for weldability determinations. The method used to determine the RVI component neutron fluence values was the Radiation Analysis Modeling Application (RAMA) fluence methodology which was approved by the NRC for specific RVI components. Although the NRC approval was for specific components (core shroud and top guide), the methodology is appropriate for other components since the methodology has been utilized throughout the industry for RVI component fluence determinations. The calculated component fluence is compared to conservative criteria to determine if a threshold value was crossed to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), to determine crack growth rates, and support weldability determinations. Ongoing inspections of the RVI components for age-related degradation due to neutron irradiation are also performed in accordance with the BWR Vessel Internals (B.2.1.7) program.

The Neutron Fluence program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor pressure vessel components. This includes but is not limited to the neutron fluence inputs for the reactor pressure vessel upper-shelf energy analyses (or equivalent margin analyses, as applicable to the CLB) and pressure-temperature limits analyses that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) include those for mean RT_{NDT} and probability of failure analyses for BWR reactor pressure vessel circumferential and axial shell welds, BWR core reflood design analyses, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms. Plant issues or conditions resulting in non-compliance with the requirements of 10 CFR Part 50, Appendix G or 10 CFR Part 50, Appendix H are entered into the corrective action program. If the neutron fluence assumptions in RPV analyses or augmented inspection bases for RVI components are projected to be exceeded, corrective actions can include updating the analyses for the RPV components or assessing the need to revise the augmented inspection bases for RVI components.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance (B.2.1.20) program provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant Technical Specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

NUREG-2191 Consistency

The Neutron Fluence Monitoring aging management program will be consistent with the ten elements of aging management program X.M2, "Neutron Fluence Monitoring" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancement will be implemented in the following program elements:

1. Perform periodic monitoring of reactor pressure vessel and reactor vessel internals accumulated neutron fluence, every refueling cycle, to ensure that neutron fluence projections used to support reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs, pressure-temperature limits) and reactor vessel internals aging effect assessments remain bounding with respect to actual plant operating conditions. **Program Elements Affected: Preventive Actions (Element 2), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)**

Operating Experience

The following examples of operating experience provide objective evidence that the Neutron Fluence Monitoring program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, an aging management program effectiveness review was performed of activities currently performed that are associated with the Neutron Fluence Monitoring program in support of preparing the license renewal

application for second license renewal. The purpose of the aging management program effectiveness review was to verify the existing Neutron Fluence Monitoring program activities are being effectively implemented during the first period of extended operation. The objective of the Neutron Fluence Monitoring program is to manage the loss of fracture toughness as a result of neutron irradiation embrittlement of the reactor vessel and reactor vessel internals.

Key program activities from 2003 to present were reviewed. Key activities of the program that were reviewed included program updates resulting from plant modifications. Since 2014 (Unit 2) and 2015 (Unit 3), Peach Bottom implemented an Extended Power Uprate (EPU) from a licensed thermal power of 3514 megawatts thermal (MWt) to 3951 MWt, implemented the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy, and a Measurement Uncertainty Recapture (MUR) power uprate of 1.66 percent to a level of 4016 MWt. The changes in core neutron fluence associated with these plant licensing modifications resulted in a revision to the associated fluence projections and associated RPV irradiation embrittlement analyses. The revised neutron fluence projections were utilized as inputs in the current licensing basis RPV neutron irradiation embrittlement analyses for Unit 2 and Unit 3 beltline components, including analyses of upper-shelf energy (USE), adjusted reference temperatures (ART), pressure-temperature (P-T) limits, axial and circumferential weld failure probability, and RPV and core shroud reflood thermal shock utilizing GE Discrete Ordinates Transfer (DORT) fluence methodology. These revised neutron fluence exposures were also used as input in analyses of PBAPS Unit 2 and 3 reactor vessel internals components, including the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware) utilizing Radiation Analysis Modeling Application (RAMA) fluence methodology.

During performance of the effectiveness review, it was noted that the monitoring of changes in neutron fluence were performed as a result of plant modifications. Routine monitoring of neutron fluence was not performed on a routine basis. As a result, the program will be enhanced to create recurring task work orders to ensure monitoring and assessment of neutron fluence occurs routinely, as well as in response to significant modifications or changes in core loading.

This example provides objective evidence that aging management activities associated with the Neutron Fluence Monitoring program are being effectively performed during the first period of extended operation. This example provides objective evidence that the continued implementation of the Neutron Fluence Monitoring aging management program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the second period of extended operation.

2. Original plant licensed fluence calculations were performed with an assumed 40-year (32 EFPY) operating period. To support operation during the first period of extended operation calculations for RPV end of life fluence were completed for a 60-year (54 EFPY) operating period utilizing the GE fluence calculation methodology (NEDC-32983P). Analyses have been performed that use the calculated fluence results to address upper-shelf energy, P-T limit

curves, RPV circumferential weld examination relief, and RPV axial weld failure probability. The updated RPV P-T limit curves for 54 EFPY were incorporated into the Pressure-Temperature Limits Report prior to the end of the initial operating license term for Units 2 and 3.

This operating experience provides objective evidence that the analyses that use neutron fluence as an input are reviewed and updated, as required.

3. Industry operating experience identified that during preparation of fluence predictions to support development of revised P-T limits for the period of extended operation at another nuclear facility, it was discovered that the fluence assumptions for the current analysis were non-conservative due to a legacy error in the model and lack of margin in the extrapolation of fluence values. This resulted in the fluence assumptions for the current analysis being reached approximately two years earlier than expected, requiring the P-T limits in Technical Specifications to be declared non-conservative, requiring implementation of more restrictive administrative limits. The legacy error was discovered prior to the actual P-T limits for the RPV being exceeded.

Review of this issue resulted in revision of the corporate implementing procedure for Neutron Fluence Monitoring program to ensure that any change to core design or power distributions are reconciled with the current licensing basis pressure-temperature limit applicability date in terms of EFPY.

This operating experience demonstrates effective use of industry operating experience to demonstrate the significance of analyses associated with RPV embrittlement and effective implementation of human performance tools to ensure technical adequacy.

4. In support of the reactor vessel material surveillance program, PBAPS has withdrawn and tested capsules in accordance with 10 CFR Part 50, Appendix H. In 1987, the Unit 2 capsule located at 120 degrees azimuth was withdrawn and tested in accordance with the capsule withdrawal schedule. The capsule had received 7.53 EFPY of irradiation. The pressure-temperature curves were evaluated and updated as required. After testing, the capsule was reconstituted and re-inserted into the reactor vessel during the next refueling outage.

In 1989, the Unit 3 capsule located at 30 degrees azimuth was withdrawn and tested in accordance with the capsule withdrawal schedule. The capsule had received 7.57 EFPY of irradiation. The pressure-temperature curves were evaluated and updated as required. After testing, the capsule was reconstituted and re-inserted into the reactor vessel during the next refueling outage. During the withdrawal of the capsule located at 30 degrees azimuth, it was noted the capsule located at 300 degrees azimuth was detached from the wall mounting bracket. The capsule located at 300 degrees azimuth was removed, stored in the spent fuel pool, and re-installed in the vessel during the next refueling outage.

This operating experience provides objective evidence that the existing Reactor Vessel Material Surveillance (B.2.1.20) program adequately monitors the loss of fracture toughness of the reactor vessel beltline materials due to neutron irradiation embrittlement.

5. In 2003, PBAPS obtained NRC approval to participate in the BWR Vessel and Internals Project Integrated Surveillance Program (ISP), which is currently described in BWRVIP-86-R1-A: BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan. PBAPS Unit 2 is designated as a host plant and is scheduled to withdraw and test a capsule in 2018 and subsequently benchmark against existing neutron fluence analyses. PBAPS Unit 3 is designated as a non-host plant and is aligned with River Bend Station for weld material and Duane Arnold Energy Center for plate material. River Bend is scheduled to withdraw and test a capsule in 2025. Duane Arnold withdrew and tested a capsule in 2012. The results of the Duane Arnold capsule were evaluated for PBAPS Unit 3 and no changes to the Unit 3 adjusted reference temperatures (ART) or pressure-temperature curves were required. Duane Arnold is scheduled to withdraw and test their next capsule in 2027.

The operating experience relative to the Neutron Fluence Monitoring program did not identify an adverse trend in performance. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Neutron Fluence Monitoring program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Neutron Fluence Monitoring program will provide reasonable assurance that the loss of fracture toughness aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

B.3.1.3 Environmental Qualification of Electric Equipment

Program Description

The Environmental Qualification of Electric Equipment aging management program is an existing preventive program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants.” The program includes electric equipment composed of various polymeric and metallic materials that is important to safety. This electrical equipment could be subject to harsh environmental effect of a loss of coolant accident (LOCA,) high energy line break, or post LOCA environment. This electrical equipment could be subject to an adverse localized environment due to temperature, radiation, or moisture. The program establishes, demonstrates, and documents the TLAA analysis, level of qualification, qualified configurations, maintenance, surveillance and replacements necessary to meet 10 CFR 50.49. A qualified life is determined for equipment within the scope of the program and appropriate mitigative actions such as replacement, refurbishment, or reanalysis are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. Changes to material activation energy values as part of a reanalysis are justified. Activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years will be added to the program prior to the second period of extended operation.

If an EQ component is found to be outside the bounds of its qualification basis or when an unexpected adverse localized environment or condition is identified during operational or maintenance activities, the qualification of the affected EQ equipment is evaluated in the corrective action program. Corrective actions are taken to resolve the condition.

The various aging effects addressed by this program are adequately managed so that the intended functions of components within the scope of 10 CFR 50.49 are maintained consistent with the current licensing basis during the second period of extended operation.

NUREG-2191 Consistency

The Environmental Qualification of Electric Equipment aging management program will be consistent with the ten elements of aging management program X.E1, "Environmental Qualification of Electric Equipment" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the second period of extended operation, the following enhancements will be implemented in the following program elements.

1. Add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the second period of extended operation. **Program Element Affected: Detection of Aging Effects (Element 4)**

2. Establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments. **Program Element Affected: Acceptance Criteria (Element 6)**

Operating Experience

The following examples of operating experience provide objective evidence that the Environmental Qualification of Electric Equipment program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the second period of extended operation:

1. In 2017, a program effectiveness review was performed of the Environmental Qualification Activities program as described in UFSAR Section Q.4.1, in support of preparing the license renewal application for second license renewal. The purpose of the program effectiveness review was to verify that the existing aging management program, which establishes, demonstrates, and documents the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to apply the qualification conclusions and the equipment qualified life, is being effectively implemented in the first license renewal period of extended operation in accordance with UFSAR Section Q.4.1.

The program effectiveness review was comprised of a review of issues in the corrective action program from January 2003 to April 2017, a review of EQ Binders that assessed individual component or sub-component qualified lives of less than 60 years, and an evaluation of all existing EQ related maintenance tasks in PassPort.

The program effectiveness review found that the configuration and technical basis for components in the scope of the Environmental Qualification Activities program is robust, well documented, and readily retrievable. However, the program effectiveness review found a deficiency in the scheduling of replacement activities required for EQ components and sub-components with qualified lives between 40 and 60 years.

Specifically, it was discovered that eight Unit 2 Residual Heat Removal (RHR) pump discharge pressure switches that function within the automatic depressurization system (ADS) control logic were not replaced at the end of their original qualified life in August 2016. In addition, no active work orders were found to replace four Unit 3 RHR pump discharge ADS pressure switches when their original qualified life ended in July 2017. This issue was entered into the corrective action program. A re-analysis based on actual historical room service temperatures for the pressure switches extended the qualified life of the Unit 2 pressure switches to 2030 and the Unit 3 pressure switches to 2022.

An extent of condition review concluded that most of the EQ components and sub-components with qualified lives between 40 and 60 years (approximately 70 components and sub-components) did not have active replacement work order activities in the work management system. The extent of condition review also concluded that these EQ components were within their qualified life. The specific situations were entered into the corrective action program for establishing work orders, action tracking, and trending.

The absence of work order activities scheduling these replacements is a legacy issue from around 2003. Actions are planned to ensure EQ components with a qualified life that expires during the second period of extended operation have active replacement activities in the work management system.

This operating experience provides objective evidence that the Environmental Qualification Activities program, as described in UFSAR Section Q.4.1, has been effective, overall, in the first period of extended operation in establishing, demonstrating, and documenting the level of qualification, the qualified configuration, and replacement requirements necessary to maintain the EQ component and equipment qualified lives. The deficiency in scheduling replacement activities in the work management system was resolved using the corrective action program. This operating experience also provides objective evidence that continuous improvements are made to the Environmental Qualification Activities program through self-assessments and the corrective action program.

In conclusion, the Environmental Qualification Activities program provides reasonable assurance that the EQ components will be able to continue to perform their intended functions during the first period of extend operation. Continued implementation of the enhanced Environmental Qualification of Electric Equipment program will assure that effective aging management will continue to be performed during the second period of extended operation.

2. Peach Bottom has an effective environment temperature monitoring activity utilized by the Environmental Qualification Activities program. Periodic temperature data is collected for rooms that contain EQ components. The temperature data is periodically evaluated by the EQ program engineer. The Environmental Service Condition (NE-00164) specification is the controlled source document used to help determine the qualified life of EQ components in specific rooms based on assumed design temperatures. The evaluation results are used to inform the environment specification with actual service temperatures in the monitored rooms.

For example, in January 2006, the 2005 temperature data evaluation revealed that the average service temperature in rooms 46 and 252 was slightly above the assumed design values (2.3 and 0.7 degrees F, respectively) shown in the Environmental Service Condition (NE 00164) specification. The EQ Binders for the EQ equipment in those rooms were reviewed to assure the existing qualified life analyses bound the higher measured average ambient temperatures in those rooms. Since the EQ equipment qualified life analyses assumed an ambient temperature higher than the actual measured ambient room temperatures, there was no impact to the EQ equipment qualified life.

The Environmental Service Condition (NE-00164) specification was updated to reflect the actual measured room temperatures.

This example provides objective evidence that plant operating experience that impacts the qualified life analysis of individual EQ components is evaluated and used to adjust this aspect of the Environmental Qualification Activities program, as necessary.

3. On November 20, 2015, Information Notice 2015-12: Unaccounted for Error Terms Associated with the Irradiation Testing and Environmental Qualification of Important-to-Safety Components, was issued by the NRC. The Information Notice informed the industry that in June 2014, a radiation processing vendor notified customers of a potential Part 21 Notice arising from a 10 CFR Part 50 inspection by the NRC of the radiation processing performed by the vendor at its facility. The NRC identified that the vendor had failed to ensure that the measuring and testing system used to determine the applied radiation dose to the components being tested was properly controlled. The NRC recommended a review of EQ documentation for qualified components that had irradiation testing performed by the vendor since 1987 be conducted to ensure: a) the existing radiation margin is greater than the uncertainties indicated by the vendor based on the testing location, and b) EQ documentation be revised to indicate the revised radiation margin based on the new uncertainty.

This information notice was evaluated by the PBAPS EQ Program engineer as part of the station's routine OPEX process. The event was determined to be directly applicable to the Environmental Qualification Activities program.

A complete review of EQ binders was conducted to identify if the vendor had performed the irradiations. New margins based on the additional uncertainty were determined for those EQ binders that involved vendor-performed irradiations. The review indicated that in each instance (13 out of 85 PBAPS EQ binders) where the vendor had performed the irradiations, adequate margin exists to demonstrate environmental qualification of components in scope of 10CFR50.49, thus there were no operability concerns. The impacted EQ binders were revised to capture the change in margin as required.

This example provides objective evidence that industry operating experience that involves the analysis of qualified life is evaluated and used to adjust the Environmental Qualification Activities program, as necessary.

The operating experience relative to the Environmental Qualification of Electric Equipment aging management program found that many aspects of the current Environmental Qualification Activities program are robust. A self-identified deficiency in scheduling replacement activities in the work management system was resolved using the corrective action program. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Environmental Qualification of Electric Equipment aging management program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience.

Therefore, there is confidence that continued implementation of the Environmental Qualification of Electric Equipment aging management program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the second period of extended operation.

Conclusion

The enhanced Environmental Qualification of Electric Equipment program will provide reasonable assurance that the various aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the second period of extended operation.

APPENDIX C
RESPONSE TO BWRVIP LICENSE RENEWAL APPLICANT ACTION ITEMS

Of the BWRVIP reports credited within PBAPS license renewal aging management programs, the following include NRC safety evaluation reports (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; BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26-A; BWR Top Guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27-A; BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-38; BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-41; BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (Revision 3)
- BWRVIP-42-A, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines
- BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-48-A, BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines (Credited in BWR Vessel ID Attachment Weld program)
- BWRVIP-49-A, BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal
- BWRVIP-76-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines (Revision 1)
- BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines

License renewal applicant action items identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. BWRVIP reports without SERs for license renewal do not have action items and are therefore not included in the tables.

It is recognized that the first three action items from each of the license renewal SERs applicable to the above BWRVIP reports are fundamentally identical, with the exception of BWRVIP-139-R1-A. For that reason they are combined in the table and addressed together.

Common Action Items from BWRVIP-18 R2-A, -25, -26-A, -27-A, -38, -41 R3, -42-A, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**Peach Bottom Response**
BWRVIP-AII (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 PBAPS have been reviewed and PBAPS aging management programs have been verified to be bounded by the reports. Additionally, PBAPS is committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the second period of extended operation. These commitments are included in SLRA Appendix A, Section A.5. If, upon review of a BWRVIP approved guideline, it is determined that known deviations to full compliance are warranted, the NRC will be notified of the deviation within 45 days of the receipt of NRC final approval of the guideline. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50, Appendix B.
BWRVIP-AII (2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contains a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.	The UFSAR supplements are included in SLRA Appendix A. The UFSAR supplements include a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports.

Common Action Items from BWRVIP-18 R2-A, -25, -26-A, -27-A, -38, -41 R3, -42-A, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**Peach Bottom 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 second period of extended operation. Reference SLRA Appendix D.

Additional Action Items	
BWRVIP-18-Revision 2A, Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-18 (4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV core spray internal components.	Cumulative fatigue damage is a potential TLAA issue identified for core spray system piping and components internal to the reactor vessel. TLAA is used to manage cumulative fatigue damage for these core spray piping and components as discussed in SLRA Section 4.3.6.2.

BWRVIP-25 Core Plate Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-25 (4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	Preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants that do not have core plate wedges installed. Stress relaxation of the RPV core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in SLRA Section 4.2.9.
BWRVIP-25 (5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	The BWRVIP recognizes that it is not possible to implement meaningful inspections using the inspection methods recommended in BWRVIP-25. The BWRVIP is addressing this issue and intends to develop revised guidance. The BWRVIP recommendation to document deviation from BWRVIP-25 inspection guidelines of the core plate hold down bolts is currently being implemented. A BWRVIP Deviation Disposition is in place until revised guidance for core plate bolting inspection within BWRVIP, or some other NRC-approved solution is implemented. BWR Vessel Internals aging management program Enhancement 1 requires installation of core plate wedges no later than six months prior to entering the second period of extended operation, or submittal of an inspection plan for the core plate rim hold-down bolts with a supporting analysis for NRC approval at least two years prior to entering the second period of extended operation. The installation of core plate wedges would eliminate the need to inspect the core plate rim hold-down bolts.

BWRVIP-26-A Top Guide Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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 RAMA fluence evaluation for reactor internals performed for license renewal determined that the neutron fluence threshold for IASCC susceptibility has been exceeded. Fluence for reactor internals is evaluated as a TLAA in SLRA Sections 4.2.1.2 and 4.2.14. No TLAA has been identified to manage aging effects. During the second period of extended operation, the aging of the top guide will be managed by inspections conducted as part of the BWR Vessel Internals (B.2.1.7) program per guidance provided in BWRVIP-183. The program requires that at least 10 percent of the grid beam cells containing control rod blades will be inspected every 12 years with at least 5 percent to be performed within 6 years. The inspections are performed using the enhanced visual inspection technique, EVT-1. The program also allows for inspections to be performed using UT once it becomes available. Inspections will continue to be performed as described above during the second period of extended operation.

BWRVIP-27-A Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-27-A (4) Applicants referencing the BWRVIP-27-A report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.	Cumulative fatigue damage is a potential TLAA issue identified for the SLC system/core plate dP penetration. TLAA is used to manage cumulative fatigue damage for the SLC system/core plate dP penetration as discussed in SLRA Sections 4.3.1 and 4.3.3.

BWRVIP-42-A, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines.	
Action Item Description	**Peach Bottom Response**
BWRVIP-42-A (4) Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components	Peach Bottom design does not include LPCI couplings; this action item does not apply.
BWRVIP-42-A (5) The BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR applicant notify the NRC of actions planned. Applicants referencing BWRVIP-42 report for license renewal should identify the action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff.	Peach Bottom design does not include LPCI couplings; this action item does not apply.

BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-47-A (4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	Fatigue usage is considered a TLAA for reactor vessel incore instrumentation penetrations and CRD penetrations. This is addressed in SLRA Sections 4.3.1, 4.3.2, and 4.3.3.

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-74-A (4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The vessel flange leak detection (VFLD) nozzles and piping are included in the scope of scope of license renewal. The Unit 2 and Unit 3 nozzles are made from carbon steel. Loss of material is managed by the One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program. The VFLD piping on both units is fabricated from stainless steel. Cracking is managed by the One-Time Inspection (B.2.1.21) program and loss of material is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program. Reference SLRA Section 3.1.2.2.4.
BWRVIP-74-A (5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventative actions, (3) parameters monitored and inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	There are no plant-specific aging management programs credited for managing aging of reactor pressure vessel components. Descriptions of the aging management programs credited for managing the reactor pressure vessel are described in Appendix B. These descriptions include any program element that deviates from the NUREG-2191 program element, and any enhancements that are required to meet NUREG-2191 requirements.

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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 (B.2.1.2) aging management program is consistent with NUREG-2191, Revision 0, Chapter, XI.M2, "Water Chemistry", and meets the requirements of the latest BWRVIP Water Chemistry guidelines to help ensure the long-term integrity of the reactor vessel and internals. Aging management programs that utilize inspections to perform condition monitoring of reactor pressure vessel and internal components to identify cracking also credit the Water Chemistry program to mitigate cracking of reactor vessel components, including the BWR Vessel Internals (B.2.1.7), BWR Vessel ID Attachment Welds (B.2.1.4), BWR Penetrations (B.2.1.6), and BWR Stress Corrosion Cracking (B.2.1.5) programs.
BWRVIP-74-A (7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific in-vessel surveillance program, applicable to the LR term.	The Reactor Vessel Material Surveillance (B.2.1.20) program describes the plant-specific in-vessel surveillance program that is applicable for the second license renewal term.

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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 4.3.2. Fatigue TLAAs are managed by the Fatigue Monitoring (B.3.1.1) program to ensure that cumulative fatigue usage will not exceed 1.0. Environmental fatigue for reactor vessel components is evaluated in SLRA Section 4.3.3.
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 second period of extended operation 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 second period of extended operation were determined using methods consistent with RG 1.99, Revision 2. This is discussed as a TLAA in SLRA Section 4.2.2.

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-74-A (11) To obtain relief from the inservice inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E for the staff's July 28, 1998, FSER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	At the end of the second renewal period, the circumferential welds 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.	An NRC approved methodology was used to determine fluence during the second period of extended operation, as discussed in SLRA Section 4.2.1.1.

BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-74-A (14) Components that have indications that have been previously analytically evaluated in accordance with sub-section IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be re-evaluated for the 60-year service period corresponding to the LR term.	Components within the ASME Code Class 1 reactor coolant pressure boundary with indications that have been previously analytically evaluated until the end of the first period of extended operation are evaluated to the end of the second period of extended operation. There are two flaws in the Unit 2 RPV closure head welds and three flaws in the Unit 3 RPV closure head welds that have been previously evaluated for the 60-year service period. These flaws have been re-evaluated to the end of the second period of extended operation. Reference SLRA Section 4.3.8.

BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
BWRVIP-76-R1-A (4) The applicant shall reference the NRC staff-approved TRs BWRVIP-14-A, BWRVIP-99 (when approved) and BWRVIP-100-A in their RVI AMP. The applicant shall make a statement in their LRA that the crack growth rate evaluations and fracture toughness values specified in these reports shall be used for cracked core shroud welds that are exposed to the neutron fluence values that are specified in these TRs. The applicant shall confirm that they will incorporate any emerging inspection guidelines developed by the BWRVIP for these welds.	The BWR Vessel Internals (B.2.1.7) program implements BWRVIP-76-A requirements including guidance within BWRVIP-76-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The BWR Vessel Internals program includes reference to BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-A for fracture toughness values. The implementing procedures for the BWR Vessel Internals program include guidance to incorporate new guidance within new or revised BWRVIP reports. This assures that any emerging inspection guidelines developed by the BWRVIP for these core shroud welds will be incorporated into the program. Core shroud crack growth TLAAs are discussed in SLRA Section 4.2.14.
BWRVIP-76-R1-A (5) LR applicants that have core shrouds with tie rod repairs shall make a statement in their AMP associated with RVI components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on their units and incorporated revised inspection guidelines, if any, developed by the BWRVIP.	The core shrouds have not been modified to include tie rod repairs.
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	The core shrouds (including welds) are fabricated from stainless steel and nickel alloy material. Cumulative fatigue damage for the core shroud has been identified as a TLAA as discussed in SLRA Section 4.3.6. In addition to

BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
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.	cracking, loss of material due to pitting and crevice corrosion and cumulative fatigue damage are identified as aging effects requiring aging management. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) programs will be used to manage cracking and loss of material due to pitting and crevice corrosion during the second period of extended operation.

BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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 shrouds (including welds) are fabricated from stainless steel and nickel alloy material. No core shroud repair assembly components have been added. Therefore, core shroud components that are made from materials other than stainless steel or nickel alloy are not addressed.
BWRVIP-76-R1-A (8) LR applicant shall reference the NRC staff-approved topical reports BWRVIP-99 and BWRVIP-100-A in their RVI components AMP.	The BWR Vessel Internals (B.2.1.7) program implements BWRVIP-76-R1-A requirements including guidance within BWRVIP-76-R1-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The current guidance includes letter 2012-074 from Randy Stark, EPRI, BWRVIP Program Manager, to All BWRVIP Committee Members, Superseded “Needed” Guidance Regarding Crack Growth Assumptions, March 22, 2012 for evaluation of crack growth rates in austenitic stainless steel and nickel based alloy components. This guidance is consistent with BWRVIP-14-A and BWRVIP-99-A. The 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-A for evaluation of crack growth.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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.	PBAPS Units 2 and 3 replacement steam dryers are Westinghouse Nordic steam dryers, therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom 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)	
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.	PBAPS Units 2 and 3 replacement steam dryers are Westinghouse Nordic steam dryers, therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.
BWRVIP-139-R1-A (3) Identification of Time Limited Aging Analyses License renewal applicants are required by 10 CFR 54.21(c)(1) to identify all analyses in the CLB that conform to the six criteria in 10 CFR 54.3(a) for defining an analysis as a TLAA. For those BWR license renewal applicants that confirm that the CLB includes a steam dryer	PBAPS Units 2 and 3 replacement steam dryers are Westinghouse Nordic steam dryers, therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Peach Bottom Response**
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.	

APPENDIX D - TECHNICAL SPECIFICATION CHANGES

10 CFR 54.22 requires that an application for license renewal include any Technical Specification changes or additions necessary to manage the effects of aging during the period of extended operation.

No Technical Specification changes or additions were identified as necessary to manage the effects of aging during the second period of extended operation and as such no Technical Specification changes or additions are included with this Second License Renewal Application.